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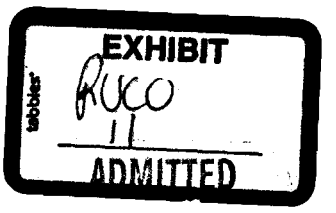

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. W-01933A-15-0322

SURREBUTTAL TESTIMONY AND SETTLEMENT TESTIMONY

OF

LON HUBER

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 25, 2016

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INTRODUCTION

Q. How is your Surrebuttal Testimony organized?

A. I intend to first provide a summary of RUCO's position, then address the rebuttal testimonies of witnesses Overcast and Jones together in the following format:

1. RUCO's recommendations
2. Allocation of Distribution System Costs
3. Rate Mechanism for Recovery of Fixed Costs
4. Recent Fixed Charge Proposals
5. Concerns Regarding Fixed Charges
6. Earnings Risk
7. Tiered Rates

Q. Do you have any corrections to your direct testimony?

A. Yes, on page 32 line 14, strike RUCO and insert TEP.

Q. Do you have any modifications or additions to your rate design proposals presented in your Direct Testimony?

A. Yes, based on the recent UNS Electric ACC decision, I recommend several modifications to the positions put forward in my Direct Testimony. These include:

1. Recommend setting the fixed charge on Time-of Use ("TOU") based rates to $10 and $13 for non-TOU or demand rate plans

2. Recommend adopting a two window winter peak for the RUCO default TOU rate
3. Recommend adopting RUCO's RPS Credit option (also labeled the RES Credit option in Direct Testimony) in the interim before Phase II. Customers could have the option to apply the credit rate on all their production or just exports.
4. Recommend the approval of TORS program
5. Recommend a $6 meter fee in the interim for those on the net metering rider

One could argue that the theme of the UNS Electric rate case was the modernization of rates. In fact, Judge Rodda in the ROO for UNS Electric rate case may have put it best when she said "the time is ripe for a more modern rate design."[1] In the UNS Electric decision, a strategy was implemented to take the beginning steps of modernizing rates by:

- Incentivizing customers on two-part traditional rates to switch to a Time-of Use ("TOU") based rate. This is because TOU based rates align closer to system costs and send better price signals to customers than a two-part traditional rate. The strategy implemented sets a date for transition, about six months out, when the fixed charge on all TOU based rates will be reduced from $15 to $12. The fixed charge on the two-part traditional rate would remain at $15. This $3 differential will provide the incentive for customers to select a TOU based rate.

[1] UNS Electric Recommended Opinion & Order Page 66 Line 9

- The two-part TOU rate offered by UNS Electric, now becomes the default rate for all new residential customers.
- Addressing the Company's three-part mandatory demand charge for DG customers and changes to net-metering, were moved into a Phase II which is to commence once the open Value of Solar Docket has concluded.
- RUCO's RPS Credit option was adopted as another option for DG customers that provides certainty for both DG customers and non-DG customers alike and is not reliant on rate design for DG customers or the Value of Solar docket.
- A meter charge was implemented for DG customers to account for the increased costs of providing service to a DG customer.

1. RUCO's Recommendations

a. Rate Design for All Residential Customers

Q. What is RUCO's recommendation regarding fixed charges for residential customers?

A. In order to modernize rate design and incentivize the adoption of more TOU rates, RUCO recommends a strategy much like that adopted in the UNS Electric rate case. The fixed charge for all rates should be increased to $13 after the Commission order. An educational campaign, lasting six months from the date of final order, should then be undertaken, by the Company, to educate customers about TOU rates and the tools provided to allow customers to control their usage and be successful on these types of rates. At the end of the six months, the fixed charge on TOU based rates should be reduced to $10. This provides the same

incentive as the UNS Electric rate case, enticing customers to transition to TOU rates. Although there is no evidentiary basis for a fixed charge higher than $10, raising the fixed charge to $13 provides the needed amount of fixed charge differential to create an incentive for customers to select TOU based rates. The proposed timing also minimizes the argument that increasing the fixed charge only on two-part traditional rates is punitive.

Q. What is RUCO's recommendation for a default rate for residential customers?

A. RUCO continues to recommend that the Company's default rate for new residential customers, and large customers, should be RUCO's two-part TOU rate. This recommendation continues the theme of modernizing rates, while maintaining customer choice.

Q. Did the UNS Electric decision provide a guide for the TOU periods?

A. Yes, a four hour peak period with two time windows for the dual winter peak. RUCO's proposed default TOU had this exact same four hour window. To conform with Commission direction regarding the winter peaks and the fixed charge differential, I have slightly modified RUCO's proposed default TOU.

Full Requirements TOU Rate

Basic Monthly Service Charge	$10.00

Delivery	Summer	Winter
On-Peak	0.178	0.12
Off-Peak	0.058	0.051

Fuel	Low User	Medium User	High User
Floor (kWh)	0	500.01	1000.01
Ceiling (kWh)	500	1000	
Rate	0.011	0.0241	0.0421

	Summer	Winter
Start Month	May	October
End Month	September	April

Peak Hours	Summer	Winter
Peak Hour Start	3:00 PM	6:00 AM & PM
Peak Hour End	7:00 PM	9:00 AM & PM

Basic Charge spread 3 ways

fuel charges

Three-Part Optional Rate

Basic Monthly Service Charge	$10.00

Demand Charges	Summer	Winter	kW Break Point
Below Break Point	$4	$2	4.50 kW
Above Break Point	$12	$4	

Delivery	Summer	Winter
On-Peak	$ 0.1690	$ 0.0950
Off-Peak	$ 0.0385	$ 0.0295

Fuel	Low User	Medium User	High User
Floor (kWh)	0	500.01	1000.01
Ceiling (kWh)	500	1000	
Rate	0.011	0.0241	0.0421

	Summer	Winter
Start Month	May	October
End Month	September	April

Peak Hours	Summer	Winter
Peak Hour Start	3:00 PM	6:00 AM & PM
Peak Hour End	7:00 PM	9:00 AM & PM

b. RPS Credit Option

Q. In light of the procedural order that created a Phase II for this rate case, should RUCO's recommendations of the RPS Credit option and meter charge be pushed to Phase II?

A. No, the idea of the Phase II proceeding, in this case, came from the UNS Electric rate case and RUCO would argue that it is designed to mirror it. The motion filed by the Company in this case, requesting a Phase II proceeding, is limited in scope to "changes to net metering and mandatory three-part rates for new DG customers." The language in the procedural order limits the scope of Phase II to issues "related to changes to net metering and rate design for new DG customers." Neither the RPS Credit option nor the meter charge for DG customers falls within either of these scopes. If one were to argue that they did, they would also, by implication, have to argue that revenue allocation, revenue requirement, and fixed charges are also related. This type of reasoning seems to go far beyond the spirit and intent of the Phase II proceeding, which is to wait until the Value of Solar docket is complete to make decisions on issues in this case, that are directly impacted by that docket.

Additionally, in the UNS Electric rate case, Commissioners Stump and Tobin each proposed amendment that were subsequently adopted unanimously by the commission, specifically relating to RUCO's proposed RPS Credit option and the metering charge for DG customers. By the Commissioners not pushing these issues to Phase II, they demonstrated that these issues either 1) needed to be addressed with some urgency or, 2) as RUCO suggests, there was no need to wait because they were separate from the issues directly related to the Value of Solar docket. Either way, it is clear that there is no need to push these issues into the

Phase II proceeding. Now is the time to address them. Keeping these options on the table for Commissioner consideration, as intended, is the prudent thing to do.

Q. Does RUCO still support the RPS Credit Option?

A. Absolutely, with one modification. To accommodate concerns heard from solar roof top representatives, RUCO now allows a choice to prospective solar customers about whether or not they want the credit rate applied to all of their production or just exports.

Q. Do export only customers fully count towards the capacity in a given tranche?

A. Yes, the full system capacity would apply.

Q. For the "Capacity per Tranche" figures in your Direct Testimony, please provide the basis for the level of capacity in each tranche.

A. The basis for each capacity tranche in the RPS Credit Option was formulated to create an average blended rate across all tranches of around 7.7 cents/kWh. This conforms with RUCO's long-term breakeven analysis. The capacity targets are also close to yearly REST compliance targets.

Q. For the "Price per Tranche" figures in your Direct Testimony, please provide the basis for the rate level in each tranche.

A. RUCO attempted to set the decline rate roughly equal to historical system cost declines. RUCO chose a yearly 7% decline rate. Reported system prices of residential and commercial PV systems declined 6%–7% per year, on average, from 1998– 2013, and by 12%–15% from 2012–2013 (depending on system size).[2]

Q. Please indicate whether and how the proposed rate for the final tranche would be updated over time.

A. The final rate would be the Market Cost Comparable Conventional Generation ("MCCCG") rate plus any adder the Commission deems reasonable in a post-RPS compliance environment to recognize the local renewable energy attributes. The MCCCG rate is updated every year.

Q. Can a customer's fixed charge be reduced through the RPS credit Option?

A. Assuming a large enough system, yes.

Q. Are there other details to call out?

A. Perhaps. RUCO does not intend to stray from current DG related rules when approaching the RPS Credit Option. For example, a bill could not go negative and

[2] Photovoltaic System Pricing Trends, 2014 Edition, US DOE SunShot: http://www.nrel.gov/docs/fy14osti/62558.pdf

any excess would be paid out at wholesale rates during the same time period that currently exists for NEM.

Q. What about concerns of customer confusion with the step downs?

A. Just like UFI's, I fully expect the Company will provide adequate notice when a capacity tranche starts to run out of capacity. As an example, like years before, TEP would notify the installer listserv and post a message on the website.

Q. Can capacity levels and credit rates be adjusted on a going forward basis in the months and years ahead?

A. Absolutely. The structure is very flexible to accommodate new policy directions, technology, locational data, etc. Unlike net metering, the RPS Credit Option can accommodate the following:

1. State policy goals that guide the capacity targets
2. Locational value, technology (west facing, advanced inverter) and reliability adders can be integrated into credit rates
3. Regular check-ins can occur at Commission discretion to respond to changing market conditions and technological developments
4. More peak demand based rates because the value proposition does not depend upon the underlying rate design, so one can couple EE and demand reducing technologies with solar without tradeoffs.

Finally, if the Commission so wishes, the RPS Credit Option can easily be adapted to incorporate the outcome of the Value of Solar docket.

Q. Did RUCO review the TORS program?

A. Yes, RUCO reviewed the TEP Owned Residential Solar (TORS) program with a particular focus on the cost parity issue. I found that TEP owned rooftop solar were 44% less expensive than a NEM based PV system on current rates. While that figure drops to approximately 25% less expensive, if a societal time value of money rate is applied, I did not factor in lost adjuster revenue or local tax revenue losses from NEM based systems.

Q. Does this conform with earlier opinions on the program?

A. Yes, and then some. The benefits to ratepayers is higher than anticipated and I am not even factoring in other possible benefits of the TEP program that are not provided by NEM based systems. What the analysis points to is that rooftop solar can be obtained for a much lower price to the benefit of all ratepayers.

Q. Do existing TORS systems align with the cost parity principle?

A. Yes.

Q. Does RUCO continue to support the expansion of the TORS program?

A. Very much so.

c. Meter Fee

Q. Does RUCO recommend a $6 meter fee for net metering customers?

A. Yes.

Q. How did RUCO arrive at this figure?

A. RUCO utilized TEP filed REST implementation plan budgets to determine that the Company charges for the direct hardware costs of solar specific metering through the REST surcharge. RUCO then examined the TEP marginal cost study CAJ-1, Schedule 1, to estimate the administrative costs and the monthly hardware related costs per customer. To simplify the calculation, RUCO made the assumption that there is not a substantial cost difference between a standard residential AMR meter and a PV production meter. This relates to both hard and soft costs. To formulate the monthly amount from the marginal cost study, RUCO added lines 5, 13, half of line 14, 18, 19, and 20 to arrive at a figure around $6 per month. It is important to note that this figure errs on the conservative side because it does not take into account the incremental additional cost of an "upgraded" bi directional meter a solar customer also needs.

2. Allocation of Distribution System Costs

Q. Are there cases where public utility commissions have adopted the use of the basic customer method over the minimum system method to allocate distribution system costs?

A. Yes, there are many. I will provide just a few examples. In Utah, the Public Service Commission adopted a classification system mostly based on demand and rejected use of the minimum distribution system method[3]. In Washington, the Commission also rejected the minimum system method stating that "the minimum system method is likely to lead to the double allocation of costs to residential customers and over-allocation of costs to low-use customers.[4]" In Maryland, in a case with Baltimore Gas and Electric, the Commission approved the NCP method and rejected the minimum size method[5]. According to witness Baatz, "the basic service method (also known as the basic customer method) is a common method used in over 30 states."[6]

Q. Please summarize the Company's argument against use of the basic customer method to allocate customer costs.

A. The crux of the Company's argument against the basic customer method is reflected in the following statement by witness Overcast: "advocates of the basic customer method fail to recognize that class NCP is more appropriately used in

[3] Utah PSC Order, Docket No. 81-035-13.
[4] WUTC v. Puget Sound Power and Light Company, Cause U-89-2688-T, Third Supp. Order, P. 71, 1990.
[5] Maryland PSC Case No. 8070.
[6] Baatz, p 9, line 7

circumstances where there is far more diversity in load (e.g. at the substation). Class NCP alone is inappropriate for local facilities that are closer in proximity to customers they serve."[7]

Q. What is the problem with this reasoning?

A. What witness Overcast fails to mention is that there is increased diversity in load for *any* common facility that is shared among multiple users. This is true not just of transmission transformers, or substations, or feeder lines, it is true even of local branch lines feeding individual customers. Moreover, he fails to define exactly how close to the customer a facility needs to be before it becomes a "customer facility." No clear rationale or boundary is presented for when and where certain facilities that are common to many users should be considered customer-related costs versus demand- or energy-related costs.

Q. What does RUCO believe the appropriate boundary should be?

A. RUCO believes that any common facility that has the potential to be shared by multiple users should not be classified as a customer-related cost, and therefore should not be recovered through a fixed customer charge. Failure to provide this clear boundary would create a slippery slope whereby any common facility – all the way up to the power plant – could be labeled as a "customer cost." Such an

[7] Overcast, p 13, line 20

outcome is neither fair nor logical, and would not promote efficient consumer behavior.

Q. What does RUCO think the Company intends to propose in the long term?

A. The CCOSS completed by the Company indicates each customer incurs a fixed cost of $93.61 per month[8]. It can be inferred that the Company aspires to a $93.61 per month customer charge in the long term. The discussion of increased fixed charge beyond the current $10 per month and even the proposed $20 per month in this docket will likely just continue unless the Commission establishes a clear precedent for which costs are appropriate to include in a fixed customer charge.

Q. Why is a discussion of a fixed charge between the current $10 per month and the CCOSS $93.61 per month concerning?

A. Not only is RUCO is deeply concerned about the prospect of a $93.61 per month fixed charge, RUCO is also concerned that a ruling that does not address the boundaries of residential customer charges will make this topic one of the most contentious issues in all future rate cases. Utility fixed costs are not a new occurrence; utilities have always had high fixed costs. Moreover, the ask for higher charges are not due to the availability of any new technologies. Therefore, without a fence line, the Company is likely to continue to propose increasingly higher fixed charge between the currently approved customer charge and the CCOSS $93.61.

[8] Direct Testimony of Craig Jones p. 44, line 2

Q. Witness Overcast claims that the basic customer method is at odds with the NARUC Electric Utility Cost Allocation Manual. Is this true?

A. This does not appear true from the evidence presented. Overcast points to a passage from the NARUC Manual which states that "the utility must classify distribution plant data separately into demand- and customer- related costs."[9] However, the basic customer method also does this. The only difference is that the basic customer method classifies customer-related distribution costs more precisely than what the Company has proposed. That is, the distribution plant designated as customer-related is limited to the service drop and customer meter.

Q. Does the NARUC Manual provide any caveats on the use of the minimum system method?

A. Yes. The manual states: "Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost."[10]

[9] Overcast, p 14, line 14.
[10] NARUC, Electric Utility Cost Allocation Manual p 95.

Q. What limitations could there be in relying on any approach outlined in the NARUC manual?

A. Generally speaking, traditional cost classification methodologies, including those outlined in the NARUC Manual, start from the premise that there are only three types of cost drivers: energy, demand, and customer. In reality, there could be many, many more factors that are left out of this initial list. For example, in a rural community the number of poles, and length of conductor required may be more linked to the distance to reach each remote property than it is to the overall number of customers. However, the manual does not include a "Distance from Substation" classification through which these incremental costs could be assigned. Thus, the default tendency is to assign costs driven by these other factors (other than energy, demand, or customer) to the customer category, even if they are not customer-driven.

Q. What does RUCO suggest to overcome these limitations?

A. Short of a radically different method for classifying costs that includes a variety of other factors, RUCO believes that a fair way to allocate costs is to apply a "benefits received" principle.

Q. What other literature does Overcast cite in support of the minimum system method?

A. Most of the writings that Overcast cites are decades old, including articles from 1891 (Clark), 1896 (Greene), 1900 (Doherty), 1919 (Eisenmenger), 1956 (Caywood), 1963 (Bary), and 1991 (NARUC).

Q. How does RUCO think these texts should be considered?

A. We should approach these with caution. By Overcast's own standard, reports as recent as 2000 are "dated" and do not "have the advantage of the latest empirical research[11]." Relying predominantly on older writings suggest that industry practices and thinking have not changed over the last 25 to 125 years. It also presents a false notion that there is some scientifically perfected approach to cost allocation that has evolved over the years. The reality is that there is always some subjectivity involved and there are many just and reasonable rates that commissions have adopted over the years that do not conform to the minimum system approach.

[11] Overcast, p 39, line 20.

Q. Witness Overcast claims to present empirical evidence proving a causal relationship between distribution system costs and number of customers. Does RUCO believe the empirical data presented supports this conclusion?

A. No. Overcast presents two pieces of evidence to support this claim, but neither succeeds in proving causality.

Q. Please explain.

A. The first piece of evidence presented is a regression analysis in which customers are set as the independent variable and distribution plant costs are set as the dependent variable[12]. However, Overcast's approach omits many other potential explanatory variables, besides number of customers, that could also be used to demonstrate causality. In fact, Omitted-Variable Bias is recognized by statisticians as one of the major pitfalls that must be avoided in any statistical analysis that is seeking to demonstrate causality[13]. There are many potential explanatory variables that Overcast omitted in his analysis, including total kWh sales, total kW demand, size of the typical or average new customer (kW), size of the customer lot (acreage), geographic location, distance from substation, local jurisdiction, time, value of assets that have reached their useful life (among a long list of others). Without a comprehensive analysis of these and other variables it is not possible to conclude that distribution costs have a causal link specifically to number of customers.

[12] Overcast, p 36, line 18.
[13] See for example: http://statisticalhorizons.com/prediction-vs-causation-in-regression-analysis

Q. Does the Company agree that costs classified as "customer costs" could be driven by factors other than the number of customers?

A. Yes. In his direct testimony, witness Jones stated: "a utility incurs costs based on: (1) the number, *size, geographic location and type* of customers; (2) a combination of several measures of customer demand; or (3) a measure of the energy used by customers"[14] (emphasis added).

Q. What other evidence does witness Overcast provide?

A. The second piece of evidence includes a table examining the number of distribution transformers used by the residential class compared to the total system[15]. There are two problems with this analysis. First, the total number of transformers used by the residential customer class may not be reflective of the total cost of those transformers. Second some transformers could be used by multiple customer classes. Without insight into both of these factors, it is not possible to conclude which allocation method better reflects distribution cost causation.

[14] Jones, direct testimony, p 18.
[15] Overcast, p 37, line 4.

3. Rate mechanisms for recovery of fixed costs

a. Using fixed charges to recover fixed costs

Q. Does witness Overcast's rebuttal testimony on page 29 accurately characterize RUCO's position on recovery of fixed costs via fixed charges?

A. No. Witness Overcast misinterprets RUCO's position. RUCO has never claimed that fixed charges should never be used, or that they are never justified. But rather, RUCO is merely observing that there is no scientific based reason that fixed charges *must* be used to recover fixed costs. Moreover, there is no scientific rule regarding the amount of fixed costs that *should* be recovered in fixed customer charges. Instead, there is a great degree of subjectivity in how rates can be designed to recover fixed costs and the many considerations that must be balanced.

Q. Are there any examples in Arizona where a customer-related fixed cost was not recovered through a corresponding fixed charge for subjective policy reasons?

A. Yes. One example of this is the current policy the Commission has approved for line extensions. This is a clear case in which customer is imposing a cost on the distribution system, yet these costs are not recovered by that customer through corresponding fixed charge. In fact, the link between the specific customer and specific cost imposed is much more clear cut in that instance than what TEP has proposed. It also demonstrates that the principle of cost causation, while important, is not strictly applied or is not the sole determining factor in all cases.

Q. Given that the principle of cost causation is not the sole determining factor, what are some other considerations beyond cost causation that must be balanced in rate design?

A. There are many factors that must be balanced including economic efficiency, avoidance of undue discrimination, rate stability, and promoting efficient use of energy over the long term.

Q. Does Dr. Overcast appropriately balance all of these considerations?

A. No. Dr. Overcast seems to suggest that the overriding factor upon which rates should be determined is a narrow definition of what constitutes "economically efficient rates." In reality, academic theories about which rates are most efficient is simply one factor that must be balanced against other factors for determining just and reasonable rates, and should not overshadow other equally important factors.

Q. Witness Overcast states that "rate practitioners have recognized the need to recover fixed customer costs in fixed charges."[16] Does RUCO agree?

A. RUCO doesn't dispute the notion that there are customer-related costs, nor that this concept was conceived of long ago. RUCO agrees that recovery of a *limited set* of customer-specific costs through a fixed charge can be justified. However, we disagree with the Company about the extent of fixed costs that should be

[16] Ibid, line 18

attributed to a single customer, versus costs that are commonly shared among multiple customers, and which should not be recovered through fixed charges.

b. Matching costs and rates

Q. What rationale does the Company give for the use of fixed charges to recover fixed costs?

A. Witness Overcast states that "It is only through the use of fixed charges to recover fixed costs that the matching principle of rates is satisfied.[17]" Elsewhere, Overcast states that the matching principle "provides that the rates charged should match the costs for all customers."[18]

Q. What does the American Public Power Association say about matching rates and costs?

A. In a recent paper, APPA states that "No rate design will perfectly match costs and rates."[19] RUCO agrees with this statement.

[17] Ibid, p 30, line 7
[18] Ibid, p 19, line 10
[19] http://www.publicpower.org/files/PDFs/Rate_Design_for_DG-_Net_Metering_final.pdf

Q. Does RUCO agree that the matching principle suggests that all fixed costs should be recovered through fixed charges?

A. Not at all. Others have defined this principle as follows: "matching revenues with related expenses and investments in the time period they occur."[20] In many applications of the matching principle, the overarching concern is whether revenues collected match the costs incurred over a specific period of time, without particular consideration of the design of rates used to collect those revenues.

Q. What would be the implications of perfectly matching costs with rates for individual customers?

A. In theory, if each individual customer was charged a set of rates that perfectly matched costs, customers would experience real-time energy rates that fluctuate minute by minute to recover marginal fuel and operating costs. They would also experience a real-time demand rate to recover system generation costs which would be very high in summer peak hours and very low in the winter. They would also experience a real-time demand rate that was unique to their local distribution system. Finally, they would experience a customer charge that was unique to each individual customer and would reflect the specific costs of metering, billing, and the service drop for that customer. Any averaging of customer charges would violate the matching principle as there would undoubtedly be variations in the exact cost of the service drop and customer meter.

[20] http://www.aarp.org/content/dam/aarp/aarp_foundation/2012-06/increasing-use-of-surcharges-on-consumer-utility-bills-aarp.pdf

Q. Does TEP's proposal accomplish this?

A. No.

Q. Can you provide an example of how the Company's proposal to include distribution system costs in the customer charge (other than the service drop and customer meter) would violate the matching principle?

A. Yes. Under the Company's proposal, if a new housing development were constructed in the Company's service territory, new distribution system costs (other than the service drop and customer meter) would undoubtedly be incurred, some of which would be classified by the Company as customer-related costs. This means that existing customers would pay higher customer charges, despite not having incurred those costs.

Q. Does the minimum system method violate the matching principle?

A. Yes. By collecting revenue for demand related costs in the customer charge, the rates that result violate the matching principle. By contrast, the basic customer method limits the customer charge to a narrower set of costs that can be attributed to the customer with a greater degree of certainty and precision.

c. Use of volumetric rates to recover fixed costs

Q. Does witness Overcast's example on p. 31 successfully prove that it is "not logical" to use kWh charges to recover fixed costs?

A. No. Witness Overcast's example is flawed because it presumes that all fixed costs (including generation, transmission, and distribution) are customer-related and caused by individual customers. As a counter example, consider the same system, with two customers. Let's assume that a third customer is added to the system one year later, but the existing generation, transmission, and distribution infrastructure is sufficient to serve all three. No additional generation, transmission, or distribution costs are imposed on the system, and therefore the third customer is not a cost causer for these categories. In this case the only new fixed costs imposed would be costs to connect the new customer to the system (e.g. service drop and customer meter). If the fixed costs of generation, transmission, and distribution were recovered solely through a fixed customer charges there is no way to avoid the following dilemma: either the third customer pays nothing (which is unfair), or all three pay a fixed charge (which violates the principle of cost causation). In this case, a kWh charge is both fair and logical, since it better reflects each customer's use of the shared assets, and thus the benefits received.

Q. What does the Company say regarding the benefits received principle RUCO raised in its testimony?

A. Dr. Overcast claims that "the benefits received argument has no basis for setting rates."[21] On the contrary, the principle of "beneficiary pays" has been used extensively as a basis for allocating costs of shared network assets.

Q. Where has this principle been used?

A. The Federal Energy Regulatory Commission (FERC) has adopted a "beneficiaries pay" approach for years to allocate costs of shared transmission network assets. As it has stated, "The cost of transmission facilities must be allocated ... in a manner that is at least roughly commensurate with estimated benefits.[22]" The courts have also upheld this approach as an extension of the principle of cost causation: "To the extent a [customer] benefits from the costs of new facilities, it can be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed."[23] As FERC's example demonstrates, there is clearly a basis for considering benefits received as a consideration in the formulation of rates to recover shared network infrastructure. This aligns with the approach of recovering fixed costs through volumetric rates since kWh consumed can be seen as "roughly commensurate" with benefits received.

[21] Overcast, p 37, line 21
[22] FERC. (2010). Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Docket No. RM10-23-000, June 17, 2010.
[23] Illinois Commerce Commission v. FERC, 576 F.3d 470, 476 (7th Cir. 2009).

d. Economic theories of efficient rates

Q. Setting aside other factors that must be considered, what does this theory tell us about setting economically efficient prices?

A. Economics would tell us that the best way to set efficient prices is to allow the free market to do so. In fact, price regulation of utilities is intended to be a "second best" alternative to competition in the case of a natural monopoly. If we turn to free market as a guide, we can easily observe plenty of examples of products and services with high fixed costs that don't have fixed charges. If competition can provide regulators with any insight into efficient price formation, it is that there are no hard and fast rules about fixed costs and fixed charges. Gasoline is just one example that RUCO offered in its direct testimony but there are many others (e.g. per hour rentals, transportation services, etc). As witness Jones pointed out, and RUCO also acknowledges, there are differences in how the petroleum industry operate compared to electric utilities. Some of these factors (e.g. obligation to serve) may even compel a certain pricing regime for utilities, however, it's not readily apparent that high fixed costs is one of those factors

Q. What is the potential role of fixed charges in terms of encouraging economically efficient customer decisions?

A. A major purpose of efficient pricing is to send price signals that consumers can interpret and respond to, based on their individual preferences. However, the only customer decision that could possibly be influenced by a fixed customer charge is whether or not to connect to the system. Thus a fixed customer charge that

includes more than the marginal cost to connect to the system is by definition inefficient.

Q. What does witness Overcast say regarding the theory of efficient rates?

A. Dr. Overcast states that utilities are a "declining cost industry" and that "[u]nder the economic theory of optimal rates, the customer charge would be higher than the TEP proposed customer charge and higher even than the allocated customer costs because *marginal costs are low*."[24] (emphasis added).

Q. What does witness Jones say regarding marginal costs?

A. Jones' direct testimony includes the Company's Cost of Service Study, and reports that that marginal customer costs are *higher than* embedded costs ($29.49 per month versus $15.67 per month). As he states, "the depreciated original cost for these assets is far below the replacement cost for these assets."[25]

Q. What is RUCO's view of these statements?

A. The statements appear to be inconsistent. On the one hand, witness Overcast suggests that a higher fixed charge is partly justified due to high embedded costs and low marginal costs. On the other hand, witness Jones demonstrates the opposite -- that embedded customer costs are actually lower than marginal costs.

[24] Ibid, p 30, line 19.
[25] Jones, p 31, line 15.

4. Recent fixed charge proposals

Q. How many utilities does Dr. Overcast claim have customer charges over $20 per month?

A. Dr. Overcast claims that "there are about 1000 electric utilities with residential customer charges above $20 per month."[26] This is apparently based on data from OpenEI Utility Rate Database, which is cited in Dr. Overcast's testimony.

Q. Does RUCO have any concerns about the OpenEI Utility Rate Database?

A. Yes, I have major concerns. Many of the utility rates included in the OpenEI Utility Rate Database, cited by Overcast, are commercial, general service, or multi-family rates -- not residential rates as Overcast claims. Moreover, some rates have been closed for 20 years (despite being listed as open in the database). Other rates included in this dataset apply to mountain top service, grain-drying operations, farms, cotton gins, grain bins, RV parks, master-metered apartments, and other situations that are not single family residences. Additionally, the database includes multiple rates for the same utility, leading to a strong possibility for over counting.

Q. Upon review of the OpenEI data, are you able to accurately discern how many utilities' have customer charges above $20 per month?

A. No. It is my opinion the OpenEI database cannot be relied upon to determine the number of utilities with residential fixed customer charges above $20 per month

[26] Overcast Rebuttal Testimony at p. 32, line 14

for single-family residences due to the above mentioned integrity and categorization issues.

Q. How many utilities does Overcast claim are increasing fixed charges?

A. Dr. Overcast claims there are "literally thousands of utilities"[27] that are increasing customer charges.

Q. Is any evidence presented to support this claim?

A. No. Dr. Overcast does not provide any further details to indicate precisely how many or which utilities have adopted these increases in recent years. Moreover, he does not indicate which rate classes the charges apply to, whether these increases have been approved for implementation or merely proposed, or the magnitude of the increases being proposed or implemented.

Q. What other data might indicate how many utilities are increasing fixed charges for their residential customers?

A. According to a recent report, thirty seven utility proposals for increased residential fixed charges were decided in 2015. Sixteen of these decisions failed to approve *any* increase in fixed charges.[28] These numbers demonstrate that there are far

[27] Ibid. p. 31 line 23
[28] North Carolina Clean Energy Technology Center & Meister Consultants Group, The 50 States of Solar: 2015 Policy Review and Q4 Quarterly Report, February 2016.

fewer utilities implementing increased fixed charges than the "literally thousands" claimed by Dr. Overcast.

Q. Are there other relevant points from these reports you would like to include?

A. Yes. The NC Clean Energy Technology Center 50 States of Solar 2015 Policy Review includes several takeaways regarding fixed charges as they apply to all customers (including non-solar customers). Of the 37 fixed charge decisions that were decided in 2015, the median initial fixed charge for these utilities was $8.89 per month and the median proposed fixed charge was $17.25 per month. In nearly half of the cases (16 cases) no increases in fixed charges were approved. The approved fixed charges raised the median to $10.85 per month, an increase of $1.85 per month.[29] The Company's proposed fixed charge increase is not in line with previous decisions.

5. Concerns regarding increased fixed charges

Q. In its testimony, RUCO listed several potential concerns others have raised regarding the negative impact of increased fixed charges. Did the Company respond to these points?

A. Yes. Witness Overcast argued that these concerns were "not valid." However, RUCO did not find any of the arguments persuasive. I will elaborate on each response, and explain why the concerns listed are in fact still valid.

[29] North Carolina Clean Energy Technology Center & Meister Consultants Group, The 50 States of Solar: 2015 Policy Review and Q4 Quarterly Report, February 2016

a. Control over customer bills

Q. What did the Company say regarding the concern that customers' control over their bills will be reduced under a higher fixed charge?

A. Witness Overcast states that "the proposed rates still provide the customer control over the bill unless the customer uses zero kWh."

While it is true that most customers would still have some control over a portion of their bill, RUCO believes this concern is still valid since the degree of customer control is substantially reduced under a higher fixed charge. What is important to recognize is that the higher the fixed charge, the greater share of the overall revenue requirement is collected through this mechanism. By necessity, this means that a smaller share of overall revenue is collected through volumetric rates, and in turn volumetric rates would be relatively lower than if the fixed charge were held constant. Thus, the higher the fixed charge component of the rate, the smaller the bill reduction will be from actions pursued by a customer to reduce their consumption.

b. Rate shock

Q. Did RUCO's testimony argue the proposed rates would lead to 'Rate Shock'?

A. No. Contrary to what Dr. Overcast insinuates, RUCO did not invoke the term "rate shock" to describe the Company's proposed rates. It appears Dr. Overcast jumped to this conclusion. The term was included in RUCO's direct testimony as one

reason why some similar fixed charge proposals may have been denied or scaled back in other jurisdictions.[30]

Q. Please address Dr. Overcast's concerns regarding rate shock.

A. Despite not using the term to refer to the Company's proposed rates, RUCO would like to take the opportunity to refute the rate shock argument as presented by Dr. Overcast. The $0.33 per day presented in Overcast's testimony represents an increase of $120 per year[31]. RUCO understands the $0.33 per day is an average increase for all customers and some customers, particularly lower income customers, may be disproportionately affected by a daily increase above $0.33 per day. This is not an insignificant increase particularly for customers on fixed incomes. Additionally, low use customers (<500 kWh) would be subject to an average percentage rate increase that is more than twice as large as high use customers (>3500 kWh).

c. Low-income customers

Q. Are there any other groups that support RUCO's claim that low-income customers use less energy than higher-income customers?

A. Yes. Included in The National Association of State Consumer Advocates 2015-1 resolution;

[30] Direct Testimony of Lon Huber, p. 13 line 4
[31] Overcast Rebuttal Testimony p. 33 line 22

"data collected by the U.S. Energy Information Administration show that in a vast majority of regions called "reportable domains," low-income customers (with incomes at or below 150% of the federal poverty level) on average use less electricity than the statewide residential average and less than their higher-income counterparts."[32]

This resolution was included in RUCO's direct testimony.

Q. Dr. Overcast argues that there is "little or no correlation between low usage and poverty levels."[33] Does the evidence support this assertion for TEP?

A. Not necessarily. While some studies have shown that low-income does not imply low consumption in some parts of U.S., there is also evidence to suggest that this may not be true in the West. According to one recent study, low-income customers in three western utilities had usage 17%-27% lower than non-low-income customers, while results in the Midwest and East were mixed[34]. This study attributes this disparity to "differences in housing stock and reliance on energy-intensive heating and cooling units."

Q. Does this mean all low use customers are low-income customers?

A. No. RUCO acknowledges that some low usage customers may not necessarily be lower income, particularly those that seasonally occupy their homes. However,

[32] https://nasuca.org/customer-charge-resolution-2015-1/
[33] Overcast, p 24, line 20
[34] http://aceee.org/files/proceedings/2014/data/papers/7-287.pdf

for reasons explained above, RUCO believes the Commission should proceed with extreme caution when considering rate design options that could disproportionately affect low-use customers, since they could also disproportionately affect low-income customers.

d. Low usage customers

Q. How can TEP fairly recover fixed costs from low usage customers that are not also low-income customers?

A. Many homes in the Tucson area are only seasonally occupied during the winter. These customers are away from the Tucson area during summer and do not contribute to summer season peak, but also contribute less to overall recovery of fixed costs.

A seasonal rate option for certain low use customers that are not low-income may be able to help ensure fair recovery of costs without jeopardizing low-income customers. Several other utilities have a seasonal use rate that provides a minimum bill during times when a home may be unoccupied. Under this option, customers would aid in fixed cost recovery in a manner that is more aligned with year round customers. This approach would also be compatible with targeted assistance programs for low-income customers.

e. Efficiency and price signals

Q. Does RUCO believe that energy efficiency and price signals are the same issue as witness Overcast asserts?

A. Not necessarily. There are two distinct price signals to consider: one is the price signal that is sent by a fixed charge itself as one component of the overall rate design. The other is the price signal sent by the remaining volumetric component, which encourages reduced consumption and investment in energy efficiency.

Q. Does RUCO have any concerns with the Company's discussion of energy efficiency and price signals?

A. Yes. Overcast states that "[b]y charging rates that exceed marginal cost ... the RUCO proposal is supporting a significant loss in social welfare.[35]" Crucially, however, witness Overcast's testimony lacks specificity when discussing what constitutes marginal costs and whether these are short run or long run costs. Long run marginal costs (i.e. including investments in new generation capacity) tend to be significantly higher than short run marginal costs (i.e. fuel costs). Thus, there is ample justification to set volumetric rates that are high since that will encourage customers to reduce consumption, providing positive social benefits both in the form of avoided energy and in avoided capital investments. In contrast, there are virtually no beneficial actions that would be encouraged by a higher fixed charge.

[35] Overcast, p 35, line 15

The challenge for regulation is that there is no perfect way to recover embedded fixed costs. Regulators may have some discretion to choose whether to incorporate these costs in fixed rates or volumetric rates. However, for reasons stated above, and elsewhere in this testimony, RUCO believes there are far more reasons why volumetric rates should be preferred.

Q. What does witness Jones's rebuttal testimony say regarding higher fixed charges?

A. Jones implies that various intervenors are incorrect in claiming that "increasing the fixed charge … will lead customers to use more power."[36]

Q. Does RUCO agree?

A. No. There is no question that a fixed charge component, on its own, provides no incentive for customers to reduce consumption. Moreover, if more of the revenue requirement is allocated to and recovered through fixed customer charges, the less revenue is allocated to and recovered through other rate components that customers can control. As a result, customers will have less incentive to reduce consumption and will be likely to consume more.

[36] Jones, p 35, line 14.

6. Earnings Risk

Q. What does the Company say regarding the impact of the increased fixed charge on earnings risk?

A. The Company confirmed the general notion that rate design and earnings risk are linked. For example, the Company states that if kWh usage is reduced from the current pattern, then "system earnings will decline more than currently"[37] illustrating the link between volumetric rates and earnings risk. Additionally, witness Overcast provides the following quote: "An access charge reduces the risks of recovering residual utility embedded costs, provides greater revenue stability on existing assets for utilities, limits uneconomic bypass, and should allow utilities to achieve lower financing costs of the network on behalf of all ratepayers."[38]

RUCO estimates that under the company's original proposal, the portion of margin revenues derived from residential customers through fixed charges would increase from about 17% to about 27%[39]. Given that there is less risk inherent in revenue collected from customer charges, RUCO believes there is ample justification for

[37] Ibid, p 38, line 20
[38] Ibid, p 35, line 6.
[39] According to Schedule H-2 of the Company's testimony, there would be 4.6 million residential basic service charges assessed annually. Thus an increase from $10 to $20 represents an increase in revenue from $46M (17% of the $277M in test year margin revenues from residential) to $92M (27% of the $341M proposed margin revenues from residential).

an ROE adjustment if the Company's proposal were adopted, without the need for comparison to other companies.

7. Tiered Rates

Q. Does RUCO have any concerns regarding Jones' interpretation of any of RUCO's testimony?

A. Yes. Jones misinterprets the purpose of the table on page 26 of RUCO's testimony. RUCO agrees with Jones's general argument that customers are primarily concerned about overall bill reductions. In fact, the very purpose of this table was to illustrate the impact that changes to consumption would have on customer bills. In this context, it is the *marginal* rate that is most relevant for each group of customers, not the average rate. This is why RUCO chose to represent the marginal rate in its table.

Q. Why did RUCO choose to consider marginal rate over average rate?

A. Marginal rates are more appropriate than average rates when considering price signals and the ability for customers to control their bills and invest in more energy efficient appliances. Similarly, the marginal rate is what determines the increase in a customer's bill if they increase consumption, for example, during a hot summer. The table presented on page 26, of RUCO's testimony, accurately illustrates the change to the marginal rate that each group of customers will experience. Thus, the original conclusion remains valid; under the Company's proposal, higher tier

users will have less incentive to reduce consumption. Meanwhile, any increase in consumption for lower tier users will lead to a larger bill increase.

Q. Why were non-fuel components used in the table?

A. It was RUCO's intent to focus on the non-fuel components since the company has greater flexibility in what rates it proposes and ultimately uses to collect these costs.

Q. Mr. Jones observed that "mandating that all customers of a certain size be moved to this rate seems contradictory to RUCO's opposition of mandatory three-part rates for new DG customers." Do you agree with this characterization?

A. No. RUCO is suggesting a default TOU rate, not a single mandatory rate plan for large residential customers.

Q. Could there be implementation issues with transferring larger users to a default TOU?

A. No one said modernizing rates is easy, especially when dealing with legacy technology. RUCO does not propose TEP make this transfer right out of the gate. Once education efforts are in place, technology rollouts are near complete, etc. only then should this be done. The implementation hurdles are not insurmountable.

Overcoming them is necessary if we want smarter rates that benefit both ratepayers and the utility.

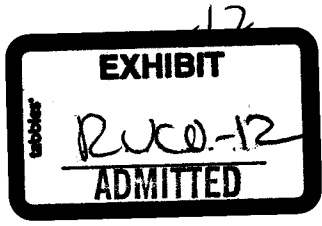
Q. Does this conclude your testimony?

A. Yes.

3/7

12

EXHIBIT
RUCO-12
ADMITTED



- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of UTAH POWER & LIGHT COMPANY for Approval of its Proposed Rate Schedules.	)))))	CASE No. 79-035-12 No. 80-035-17 No. 81-035-13 REPORT AND ORDER

Issued: March 7, 1983

Appearances:

Thomas W. Forsgren, Esq.	For	Utah Power & Light Co.
Gary A. Dodge, Esq.	"	Mobile Home Park Owners
James L. Barker, Esq.	"	Committee of Consumer Services
F. Robert Reeder, Esq. Val R. Antczak, Esq.	" "	Kennecott Corporation, et al
Michael Ginsberg, Esq.	"	Division of Public Utilities
Raymond W. Gee, Esq.	"	Utah Farm Bureau Federation, Irrigation Pumpers et al
Stephen R. Randle, Esq.	"	Salt Lake City Corporation
Margo Hovingh	"	Herself
James B. Tadje, Esq.	"	Hill Air Force Base and General Services Adm.
Robert S. Campbell, Esq. Glenn Davies, Esq.	"	Nucor Steel Corporation
Robert A. Peterson, Esq. James A. Holtkamp, Esq.	"	Chevron Resources Company
Bruce Plenk, Esq.	"	Utah State Coalition of Senior Citizens and Salt Lake Community Action Program
Peter W. Billings, Esq. Kenneth R. Pepper, Esq.	"	United States Steel Company

By the Commission:

case therefore will be the foundation for future cost of service studies the Company will present.

A. Distribution System Costs.

(1) In this Commission's April 12, 1982, Order in Case Number 79-035-12 and in its January 16, 1980, Order in Case Number 78-035-14, we held that primary and secondary distribution costs (excluding costs of customer service connection, metering, and customer accounts) would be classified as demand costs, and that such costs should be allocated on the same basis as production and transmission demand-related costs.

(2) In the Company's cost of service study presented in this case, a large portion of distribution costs that pursuant to our earlier Order should have been classified as demand costs were instead classified by the Company as customer costs. It is the Company's position that a significant amount of distribution cost should be classified as customer and not as demand. The Company argues that, otherwise, equitable rates will not be achieved because low users will not pay their fair share of the costs of the distribution system. The Company argues that a hypothetical minimum distribution system should be employed as a technique for estimating which distribution costs properly are demand costs and which customer costs. Only then, the Company argues, will each customer pay an appropriate cost of service.

(3) Both the Division witness, Alt, and the Committee of Consumer Services' witness, Coyle, presented evidence opposing the Company's proposed treatment of distribution plant.

(4) Division witness Alt presented extensive testimony that the use of a minimum distribution system to classify distribution costs results in a double allocation of these costs to low-use customers. No evidence was presented in this proceeding to the contrary. The Division's recommendation to eliminate this problem is to classify each distribution plant account either as customer or as demand, based upon engineering analysis. The Division further recommends that primary and secondary distribution plant should be classified as demand cost rather than customer cost. The Commission agrees with the analysis of Mr. Alt and will in this Order reject the use of a minimum distribution system for classifying distribution cost.

(5) Mr. Alt's testimony as shown on Exhibit (Division 3-S LEA 3) presents each distribution system account classified either as demand cost or as customer cost. It is the Commission's opinion that the Division's proposed classification of distribution accounts is reasonable and should be adopted. The Commission orders this classification to be used in future cost of service studies presented by the Company.

(6) Distribution system costs classified as demand costs are allocated by the Company to each rate schedule on the basis of each schedule's non-coincident peak. The Division, on the other hand, presented evidence that the use of a non-coincident peak for this purpose is inappropriate. Dr. Coyle, for the Committee, recommended that distribution plant classified as demand be allocated to each rate schedule on the same basis as demand-related production and transmission plant, adjusted for

Q. Any suggestions as it relates to options for DG customers?

A. Not at this moment. RUCO is open to some modification of the three options put forward; however, RUCO continues to believe that the options provide win-win outcomes for all parties involved. First, it offers an advanced TOU rate that recovers fixed costs for the company while sending strong on-peak price signals to technology adopters. Second, it offers a simple and easy to understand fixed credit payment option to less sophisticated DG customers. This option is tied to the REST goals to ensure UNS meets its DG targets. Finally, to address the need that solar advocates stress, RUCO's third options allows a solar customer to be on any rate and offset their consumption behind the meter just like today. The only difference is that exports would be restricted.

Q. Are these options complicated?

A. No, they are straightforward to understand from a customer and installer perspective. Nothing is more simple than a fixed credit rate for 20 years as outlined in the RPS credit option. This is in stark contrast to the Company's plan of having an ever changing differential export rate tied to a PPA proxy of solar PV system possibly in another utility's service territory. How would a customer know how much they export? The Company does not provide historical interval data. Even if they could get this data after waiting a full year, how could they reasonably predict savings if the rate can change in any given year?

Q. Does this conclude your rebuttal testimony?

A. Yes.

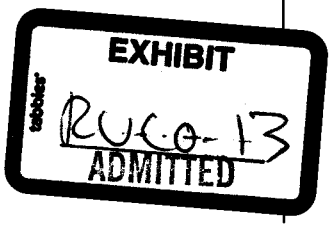


EXHIBIT
RUCO-14
ADMITTED

Q. Are there other details you would like to share about the DG TOU rate?

A. Yes, the demand charge would be determined by averaging the top three hours of demand occurring during each summer month from 2:00 PM to 8:00 PM. Also, I propose a minimum bill to recover customer related charges. RUCO initially proposes $12 to match the residential rate; however, given that a minimum bill has different dynamics than a fixed charge, RUCO would consider slightly increasing the minimum bill upwards. Finally, if a customer does not exchange renewable energy credits ("RECs") with the utility any excess monthly credits would be compensated at the MCCCG rate. This lower rate reflects the fact that UNSE may not be getting "green" energy from DG customers if the rights to that claim have already been sold or exchanged away to other states or companies.

Q. What if neither the non-export option nor the DG TOU rate is sufficient to spur DG adoption?

A. RUCO recognizes the DG carve-out policy put forward by the Commission to encourage residential distributed generation. With this in mind, RUCO believes that a straightforward and simple procurement mechanism be created to ensure REST compliance. This provides a third potential option as mentioned above.

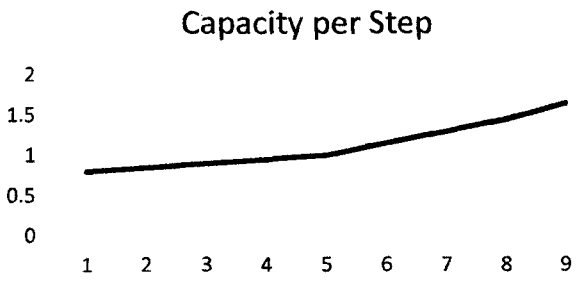
Q. Please describe the RPS credit option for DG customers?

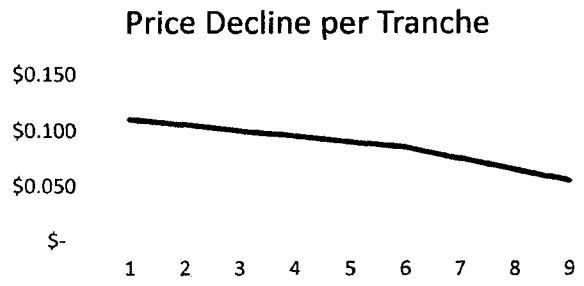
A. It is a simple fixed crediting mechanism for the output of a PV system that is linked to a specific REST procurement target. Based on the 2016 UNSE REST implementation plan, it appears that around 10 MW of residential DG is needed to meet the Commission's 2025 goal. This amount may fluctuate depending on the number of systems installed by the end

of this rate case and whether the Commission recognizes systems that have not exchanged their RECs. Exhibit 2 shows these basic calculations.

The crediting mechanism would operate much like the declining up-front incentive system the Commission used a few years ago. The credit would start at a set rate (RUCO proposes 11 cents/kWh) and would gradually decline in a predictable manner as installs increase over time. Below is an illustration of the concept and the step downs RUCO proposes:

Capacity per Tranche	Price per Tranche
0.79406351	$ 0.110
0.84369248	$ 0.105
0.893321449	$ 0.100
0.942950418	$ 0.095
0.992579388	$ 0.090
1.141466296	$ 0.085
1.290353204	$ 0.075
1.439240112	$ 0.065
1.63775599	$ 0.055





To avoid grandfathering issues and to facilitate financing, the credit rate would be fixed for 20 years. The system would be fully metered and a bill credit would be applied to a customer's bill every month. In other words, the customer's underlying rate design would not impact the economics of the transaction.

The Company would have the flexibility in each year's REST plan to recommend and adjust the terms and payment of future customers. This could include increasing the payment based on inverter capabilities or orientation of the system. Additionally, all RECs would need to be surrendered to UNSE in order to participate in this option.

Q. How would this option interface with the DG TOU rate?

A. If solar capacity is installed under the standalone DG TOU Rate (i.e. without the RPS credit), that capacity would also count towards the capacity for the REST and contribute to the step downs in the RPS credit rate. In sum, the more solar capacity that comes online, the lower the RPS credit rate for new customers.

Q. What is RUCO's anticipated ratepayer acceptance of each of the DG rate options?

A. RUCO believes that the most popular rate, at least in the beginning, will be the RPS Bill Credit option. This option provides a bridge for the industry to use in preparation for using the TOU DG Rate. With the credit rate set at $0.11/kWh and declining as additional DG capacity comes on the grid, this option most closely mirrors that of current rate design.

Customers with more sophistication and tools to control their peak loads will likely immediately select the DG TOU option. Thus, it allows the solar industry to further mature by being optional and not forcing users to be on the rate now. The solar industry will have the option of crafting tools and business plans around the advanced DG TOU, which may turn out to be more advantageous to their customers than either of the other options.

One of the benefits of the DG TOU option is that it essentially creates a floor for the offset rate of DG customers. As most DG customers in the beginning will likely choose to be on the RPS Bill Credit, and as the DG capacity hits the threshold that makes the credit rate less than the offset rate on the Advanced DG TOU ($8.5 cents/kWh), the industry can rely on the certainty provided by the Advanced DG TOU option and maintain an offset rate of $8.5 cents/kWh.

The Non-Export Option is a rate that will likely not be very popular among DG customers. This rate was designed after concurring with DG advocates who have insisted that DG customers "not be treated differently." The Non-Export option provides exactly that.

CONCLUSION

Q. Any concluding comments?

A. I believe that the rate design proposals put forward in this testimony provides benefits for all parties. Standard residential customers will see little change and hopefully will be able to take advantage of an improved TOU rate. DG customers are given three different options depending on their level of sophistication. The solar industry is able to continue selling by utilizing the RPS credit option if other options do not make economic sense at this point in time. Moreover, companies that innovate have clear price signals for how to adapt their product offerings to help customers save money on the non-export and DG TOU options. The Company's concern about fixed costs losses from DG is minimized and subsides are now more transparent.

Q. What are your recommendations regarding DG customers?

A. It can be argued that UNSE's rates are in need of modernization, especially in light of the proliferation of DG options for consumers. However, RUCO believes that UNSE's proposal for DG customers can be improved. Moreover, RUCO believes that it is possible to create a "win-win" from new advances in technology for both customers and the utility by creating options for DG and non-DG customers alike. We believe any rate design changes specific to DG customers should carefully consider unintended consequences especially given the fact that 98 percent of ratepayers in UNSE territory do not employ solar DG. As such RUCO's aim is to find a middle path that matures the rooftop solar industry while ensuring fairness for all ratepayers, balances cost-recovery with pro-conservation price signals, and which eschews the imperfect proposal proposed by UNSE. I provide three options for DG customers.

1. A non-export option.
2. An advanced DG TOU Rate.
3. Renewable Portfolio Standard ("RPS") bill credit arrangement tied to compliance.

	Non-Export Option	Adv. DG TOU Option	RPS Bill Credit Option
Rate Option:	Customer can select any of UNSE's traditional rates	Three part rate: • Minimum bill - $12 • Base Energy Rate ($0.085/kWh) • TOU Demand ($19.50/kW, 2-8pm summer peak) • Customer must be on rate for full calendar year so they do not gain the benefit of lower costs during winter but avoid higher costs during summer.	Customer can select any of UNSE's traditional rates
Export Rate:	No export of excess power to grid, therefore, no month to month carryover and no grandfathering is required. RUCO may also be open to having instantaneous exports be paid at wholesale rates.	Export rate of excess power to grid, for customers who exchange Renewable Energy Credits ("RECs") with UNSE, is $8.5 cents/kWh. For customers who does not exchange RECs with UNSE, the export rate is the Market Cost Comparable Conventional Generation ("MCCCG") rate.	Credit rate decrease over time, based on increased renewable energy capacity added to the UNSE's energy portfolio. The rate would start at 11 cents/kWh and go no lower than MCCCG rate. This credit rate would be locked in for a 20 year term. In order for a customer to take advantage of this rate, the customer would have to exchange RECs with UNSE

2016

retail sales), as well as the capacity and expected production from DG facilities that the Company holds title to the REC's.

Table 4. DG Compliance

2016	Est. DG Req't (kWh)	Capacity (kW)	Est. REC's Available
Residential	81,573,750	32,030	62,947,228
Non-Residential	81,573,750	47,030	90,862,229

In the Company's request for a waiver of the residential DG requirement, TEP requests that the Commission consider the additional 35,520 kW of residential DG capacity that is currently operational or under construction.

TEP is including in the Plan funds for performance-based incentives ("PBI") awarded in prior years, before those incentive programs were discontinued. To fund these programs, the budget for the proposed incentive program is $7,192,720.

G. Market Cost of Comparable Conventional Generation

Consistent with the REST Rules, TEP calculates program expenses using the Market Cost of Comparable Conventional Generation ("MCCCG"). Details on the methodology for the MCCCG calculation are included in Exhibit 2 attached hereto. The annual MCCCG rates are calculated in advance and stated as a single dollar per MWh value by technology type. The expenses are based on the PPA pricing after subtracting the corresponding MCCCG based on projected hourly energy profiles and are included in Exhibits 3 (AMCCG)(confidential) and Exhibit 5 (Implementation Plan New Resource Costs)

2017

Table 3. Annual Revenue Requirement for the Buildout Plan by Project

Utility Owned Solar Projects by Year	2017	2018	2019	2020	2021
2012 - HQ Rooftop, 0.05 MW	$ -	$ -	$ -	$ -	$ -
2014 - White Mountain Solar, 10 MW	-	-	-	-	-
2014 - Ft. Huachuca PH I, 17.5 MW	-	-	-	-	-
2015 - Sundt Augmentation, 5 MW	-	-	-	-	-
2015 - Ft. Huachuca PH II, 4.5 MW	1,090,123	1,010,015	889,005	-	-
Annual Revenue Requirement	**$ 1,090,123**	**$ 1,010,015**	**$ 889,005**	**$ -**	**$ -**

C. Distributed Generation Incentive Program

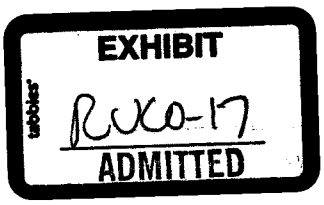
TEP is not proposing any new incentives for residential or non-residential solar DG or any other technologies. TEP anticipates that sufficient renewable DG resources will be generated in its service territory to meet the 2017 non-residential DG targets. However, since the Company no longer pays incentives necessary to acquire RECs from qualifying DG projects, it will not have an adequate number of RECs necessary to meet the 2017 residential REST requirements. Per Decision No. 75560 (May 13, 2016), TEP was granted a waiver for 2016 and 2017 of the residential DG requirement.

Table 4. Estimated DG Compliance

2017	Est. DG Req't (kWh)	Capacity (kW)	Est. RECs Available
Residential	88,028,660	32,030	53,988,550
Non-Residential	88,028,660	64,220	124,952,235
Non-Incentivized			
Residential		58,920	106,035,000
Non-Residential		48,200	86,752,800

*Does not include Wholesale Allocations (A.A.C. R14-2-1805)

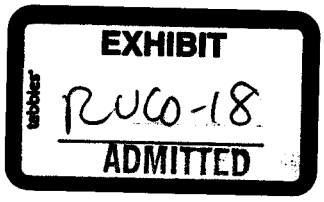
TEP is including in the Plan funds for performance-based incentives ("PBI") awarded in prior years, before those incentive programs were discontinued. To fund these programs, the budget for the proposed incentive program is $7,192,720.

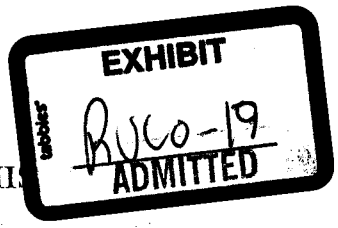


Year	Load (MWh)	End of Year REST	REST DG (MW)	REST DG (MW) Com	REST DG (MW) Residential	Δ(MW)	Capacity Release (MW)	Capacity Schedule	Decline Schedule ($/kWH)
2017	9,000,000	7%	108.0	18.0	54.0		6.0	7.0%	$0.110
2018	9,045,000	8%	124.0	20.7	62.0	8.0	6.8	8.0%	$0.100
2019	9,090,225	9%	140.2	23.4	70.1	8.1	7.7	9.0%	$0.090
2020	9,135,676	10%	156.6	26.1	78.3	8.2	8.5	10.0%	$0.085
2021	9,181,355	11%	173.1	28.9	86.6	8.3	9.4	11.0%	$0.080
2022	9,227,261	12%	189.8	31.6	94.9	8.3	10.3	12.0%	$0.075
2023	9,273,398	13%	206.7	34.4	103.3	8.4	11.1	13.0%	$0.070
2024	9,319,765	14%	223.7	37.3	111.8	8.5	12.0	14.0%	$0.065
2025	9,366,363	15%	240.8	40.1	120.4	8.6	12.8	15.0%	$0.060
								99.0%	
					Starting MW	85.4	84.57		

From 2016 REST Plan plus 2016 est. http://images.edocket.azcc.gov/docketpdf/0000162410.pdf

Current Capacity plus 2016 installs	35
Load Projection	0.50%
PV Production	1,750





BEFORE THE ARIZONA CORPORATION COMMI

COMMISSIONERS

DOUG LITTLE – Chairman
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.

DOCKET NO. E-04204A-15-0142

DECISION NO. 75697

OPINION AND ORDER

DATES OF HEARING: March 1, 3-4, 7-11, 14-18, 21, and 23, 2016

PLACE OF HEARING: Tucson, Arizona

PUBLIC COMMENT: March 22, 2016, Nogales, Arizona
March 31, 2016, Kingman, Arizona
March 31, and April 18, 2016, Lake Havasu, Arizona

ADMINISTRATIVE LAW JUDGE: Jane L. Rodda

IN ATTENDANCE: Doug Little, Chairman (Hearing & Public Comment)
Bob Burns, Commissioner (Public Comment)
Tom Forese, Commissioner (Public Comment)
Andy Tobin, Commissioner (Public Comment)

APPEARANCES:

Mr. Michael W. Patten, SNELL & WILMER, L.L.P., and Mr. Bradley S. Carroll, on behalf of UNS Electric, Inc.;

Mr. Thomas L. Mumaw and Ms. Melissa Krueger, PINNACLE WEST CAPITAL CORPORATION, on behalf of Arizona Public Service Company;

Mr. Court S. Rich and Ms. Loren Unger, ROSE LAW GROUP, P.C., on behalf of The Alliance for Solar Choice;

Mr. Jason Y. Moyes, MOYES SELLERS & HENDRICKS, LTD, on behalf of Fresh Produce Association of the Americas;

Mr. Daniel W. Pozefsky and Mr. Jordy Fuentes, on behalf of the Residential Utility Consumer Office;

Arizona Corporation Commission
DOCKETED
AUG 18 2016
DOCKETED BY

ratepayers. Public policy should not be ossified and competition, choice, innovation and market-based solutions are the preferred approach as we enter a new era dominated by customer-sited technologies and the gird upgrades and innovations that enable such technologies to exist and flourish. Potentially modernizing net metering policies based on data-drive conclusions reached in the Value of DG docket is part and parcel of the mission of ensuring rates that are just and reasonable and in the public interest.

We believe that deferring consideration of the mandatory three-part rates applicable to solar DG is warranted in order to consider the treatment of DG solar in a holistic manner and to avoid having multiple classes of DG customers, each subject to different rate treatment, due to the timing of when they elected the solar option. However there is one aspect of the DG rate design that we believe should be modified at this time. The record in this docket reflects that each DG customer requires a second meter, and that there are additional fixed costs associated with that second meter. The additional cost for the meter is $1.58. (See UNSE Updated Schedule G-6-1, Sheet 1 of 1, filed on April 4, 2016, a copy of which was also attached to UNSE's reply brief as Exhibit R-1.) This meter-related cost for the second meter required by DG customers is not being paid directly by DG customers and is currently being passed on to non-DG customers. It is appropriate for each DG customer to bear the cost of that customer's second meter. Therefore, UNSE is directed to include a $1.58 monthly charge in its Net Metering Rider to be applied to new DG customers. The revenue from this charge shall be credited to the LFCR to ensure that the charge is revenue neutral to UNSE.

Further, UNSE asserts in its reply brief that there are additional fixed costs associated with the second meter, including meter reading ($1.00) and billing and collection ($4.37) for UNSE's "costs of offsetting production from consumption and calculating credits." (UNSE Reply Brief, at 12-13.) We expect the Value of DG of docket to provide general guidance on the fixed costs of a second meter for DG customers, but company-specific testimony may also be necessary in determining the appropriate amount. Therefore, we direct the parties in Phase Two to provide testimony evaluating the other foists for the second meter required by DG customers.

Because solar DG represents such a small percentage of UNSE's current customers, and consequently a small portion of the lost fixed cost revenues, deferring a final decision on DG rates will not be a significant burden on UNSE, especially considering the revenue increase we have authorized

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Because solar DG represents such a small percentage of UNSE's current customers, and consequently a small portion of the lost fixed cost revenues, deferring a final decision on DG rates will not be a significant burden on UNSE, especially considering the revenue increase we have authorized

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-01933A-15-0322

REDACTED DIRECT

TESTIMONY

OF

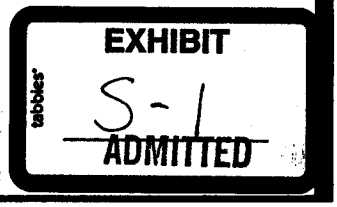
DONNA H. MULLINAX

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 3, 2016



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[redacted]

EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-15-0322 ET. AL.

The testimony of Donna Mullinax addresses the following issues, including responding to the testimony of Tucson Electric Power Company ("TEP" or "Company") witnesses on these issues:

- The Company's proposed revenue requirement
- Staff's recommended revenue requirement
- Adjusted Rate Base
- Adjusted Test Year revenues, expenses, and net operating income

Staff's findings and recommendations for each of these areas are as follows:

The Company's Proposed Revenue Requirement

TEP is requesting an increase in base rate revenues of $109.5 million, or approximately 12 percent, based on TEP's adjusted retail electric revenues at current rates of $909.3 million.

Staff's Recommended Base Rate Revenue Increase

Staff recommends that TEP be authorized a base rate increase of no more than $49.4 million on adjusted FVRB. This dollar-amount escalation is an average revenue increase of approximately five percent to adjusted test year revenues of $909.3 million.

Adjusted Rate Base

Adjustments shown in the following table should be made to TEP's proposed rate base.

Adjustment	Description	ACC Jurisdictional OCRB Increase (Decrease)	ACC Jurisdictional RCND Increase (Decrease)
		(Thousands of Dollars)	
E-1	Post Test Year Plant	$ (14,657)	$ (14,657)
E-2	Post Test Year Plant Renewables	(15,921)	(15,921)
E-3	Sundt CHF (Retirement)	20	20
E-4	ADIT	(12,814)	(12,814)
E-5	Working Capital	7,942	7,942
E-6	Depreciation	9,200	9,200
E-9	Long Term Incentive Comp	(180)	(180)
	Total Staff Adjustments	$ (26,410)	$ (26,410)
	TEP Proposed Rate Base	$ 2,104,678	$ 3,721,880
	Staff Proposed Rate Base	$ 2,078,268	$ 3,695,470

The following table summarizes TEP's requested and Staff's recommended OCRB, RCND, and FVRB, along with the differences.

Description	Company	Staff	Difference
		(Thousands of Dollars)	
Original Cost of Rate Base	$ 2,104,678	$ 2,078,268	$ (26,410)
RCND Rate Base	$ 3,721,880	$ 3,695,470	$ (26,410)
Fair Value Rate Base	$ 2,913,279	$ 2,886,869	$ (26,410)

Adjusted Net Operating Income

Adjustments in the following table should be made to TEP's proposed revenues, expenses, and net operating income.

Adjustment	Description	Pre-Tax Revenue or Expense Adjustment	Net Operating Income Increase (Decrease)
		(Thousands of Dollars)	
E-1	Post Test Year Plant	$ (1,523)	$ 941
E-2	Post Test Year Plant Renewables	(620)	383
E-6	Depreciation	(9,200)	5,682
E-7	Overhaul & Outage	(4,131)	2,551
E-8	Payroll and Payroll Taxes	(1,219)	753
E-9	Long Term Incentive Comp	(881)	544
E-10	Short Term Incentive Comp	(3,507)	2,166
E-11	Employee Benefits	520	(321)
E-12	SERP	(474)	293
E-13	D&O Insuance	(25)	15
E-14	Outside Legal	(1,340)	828
E-15	Rate Case	(144)	89
E-16	Credit Card Processing Fees	(3,476)	2,146
E-17	Interest Synchronization		(483)
	Total Staff Adjustments	**$ (26,021)**	**$ 15,587**
	TEP Adjusted Net Operating Income		$ 98,381
	Staff Adjusted Net Operating Income		$ 113,968

INTRODUCTION

Q. Please state your name, employer, and business address.

A. My name is Donna H. Mullinax. I am employed by Blue Ridge Consulting Services, Inc. ("Blue Ridge"). My business address is 114 Knightsridge Road, Travelers Rest, South Carolina 29690.

Q. Please describe your educational background.

A. I graduated with honors from Clemson University with a Bachelor of Science in Administrative Management and a Master of Science in Management. I am a Certified Public Accountant (CPA), Certified Internal Auditor (CIA), a Certified Financial Planner (CFP), and a Chartered Global Management Account (CGMA) designation holder. I am a member of the South Carolina Association of Certified Public Accountants, the American Institute of Certified Public Accountants, and the Institute of Internal Auditors.

Q. Please describe your professional experience.

A. I have over 36 years of professional experience. As of May 2016, I am President of Blue Ridge. Prior to becoming President, I held the position of Vice President and Chief Financial Officer (CFO) for the last 20 years and have served on various Boards of Directors. As Vice President/CFO, I have been responsible for all aspects of finance and administration, including accounting, cash management, tax planning and preparation, fixed assets, human resources, and benefits for my current employer and my previous employer, Hawks, Giffels, & Pullin ("HGP"), Inc.

In addition to my corporate responsibilities, I have been a utility industry consultant for the last 22 years. My consulting assignments include management, financial, and compliance audits, due diligence reviews, prudence reviews, and economic viability and financial studies.

Other projects include numerous rate cases for natural gas and electric utilities and litigation support for various construction claims. I have worked with public service commissions, attorney generals, and public advocates in Arizona, Colorado, Connecticut, Delaware, District of Columbia, Hawaii, Illinois, Maryland, Massachusetts, Michigan, Missouri, Nebraska, New York, North Dakota, Ohio, Oregon, and Utah.

From 1991 to 1993, I worked with Cherry, Bekaert & Holland CPAs as a senior accountant and accounting supervisor. My responsibilities included financial and compliance audits, financial reporting, and tax return preparation. From 1988 to 1991, I was a sales representative for Smith, Kline and French Pharmaceutical Company.

I worked with Milliken and Company, a large privately held textile and chemical company, from 1979 through 1988. As head of the Quality Assurance Department, I was actively involved in numerous operations' audits supporting Milliken's Quality Program. As the Technical Cause Analyst, I analyzed complex quality and production problems to develop corrective actions through advanced statistical and other problem-solving techniques. I conducted training seminars for production associates and management on statistical quality control techniques. I held various production management positions with the responsibility of controlling cost, schedule, production, and quality within areas under my control.

Q. Have you included a more detailed description of your qualifications?

A. Yes. A description of my qualifications is included as Attachment DHM-1.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("ACC" or "Commission").

Q. Have you previously testified before the Commission?

A. Yes. I have testified before this Commission in connection with the most recent base rate case of UNS Electric, Inc. in Docket No. E-04204A-15-0142.

Q. In what other jurisdictions have you previously appeared as a witness or filed testimony?

A. I have testified in Colorado, Delaware, Maryland, Michigan, and Nebraska. I have also supported other experts' testimonies in numerous other jurisdictions and have served as an advisor to the Commission and Staff for the District of Columbia Public Service Commission for a number of gas and electric proceedings.

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my testimony is to address the rate base, adjusted net operating income, and revenue requirements proposed by Tucson Electric Power Company ("TEP" or "Company").

Q. Are you presenting any exhibits in connection with your direct testimony in this proceeding?

A. Yes. Besides my qualifications already mentioned as Attachment DHM-1, Attachment DHM-2 includes Staff's accounting schedules, and Attachments DHM-3 through DHM-46 are copies of selected documents that are referenced in my testimony.

Q. How are Staff's accounting schedules organized?

A. Staff's accounting schedules, included in Attachment DHM-2, are organized into summary schedules and adjustment schedules. The schedules consist of Schedules A, A.1, B, C, D, D.1, E, and E-1 through E-17.

Q. What is shown on Schedule A?

A. Schedule A presents the overall summary reflecting all of the Staff adjustments, and the change in the Company's revenue requirement needed for the Company to have the opportunity to earn Staff's recommended rate of return on Staff's proposed Original Cost and Fair Value rate bases. The rate base and operating income amounts are taken from Schedules B and C, respectively. The overall rate of return, as presented by Staff witness, David C. Parcell, is provided on Schedule D for convenience.

Q. What is shown on Schedule A-1?

A. Schedule A-1 presents Staff's gross revenue conversion factor ("GRCF"), which is used to convert the net operating income deficiency into a revenue deficiency amount. The conversion factor grosses up the revenue needed to be collected from customers, recognizing that more than one dollar in gross revenue is needed for each dollar of net operating income because of the imposition of taxes on those earnings. The GRCF also recognizes that some revenues will not be collected and must be recognized as bad debt.

Q. What is shown on Schedule B?

A. Schedule B presents TEP's proposed test year Original Cost Rate Base ("OCRB") and Reconstruction Cost New Less Depreciation ("RCND") rate base. Staff's recommended rate base adjustments are also summarized to derive the "As Adjusted by Staff" OCRB and RCND balances. Staff's recommended adjustments are addressed separately in this testimony and are included within the E Schedules. The OCRB and RCND are used to determine the Fair Value Rate Base ("FVRB"). Schedule B shows the derivation of the FVRB.

Q. How was the Fair Value Rate Base determined?

A. As shown on Schedule B, the FVRB was determined by averaging the OCRB and RCND, giving equal weight to both, consistent with prior Commission practice.

Q. How did the Company develop the Reconstruction Cost New Less Depreciation rate base?

A. The RCND is derived from the Reconstruction Cost New ("RCN") and adjusted for book depreciation. The RCN is the estimated cost of constructing the Company's property at today's cost levels. A trending study establishes an index number that represents a ratio between the cost of an item in the year it was put in-service (or vintage) and its cost at a base period. The indices are applied to the Company's original cost to estimate the reconstruction or reproduction cost at current levels. Once the RCN is established, it is multiplied by a net book value percentage, which is the original cost less depreciation, divided by original cost, to develop the RCND.[1]

Q. What is shown on Schedule C?

A. The first column in Schedule C is TEP's adjusted test year net operating income. Staff's recommended adjustments to TEP's adjusted test year revenues and expenses are summarized, with each adjustment addressed separately in this testimony and included within the E Schedules. The last column provides the "As Adjusted by Staff" test year net operating income.

Q. What is shown on Schedules D and D-1?

A. Schedule D summarizes the capital structure and cost of capital proposed by the Company and the capital structure and cost of capital recommended by Staff witness, David C. Parcell.

[1] Direct Testimony of Dallas Dukes, page 36, line 8 through page 37, line 11.

Schedule D-1 isolates the impact on revenue requirements for the difference in TEP's proposed capital structure and cost of capital and that recommended by Staff.

Q. What is shown on Schedule E and Schedules E-1 through E-17?

A. Schedule E summarizes Staff's adjustments to rate base and operating income (i.e., revenues less expenses). Schedules E-1 through E-17 provide further support and calculations for the adjustments Staff is recommending.

REVENUE REQUIREMENT

Revenue Requirement Proposed by Tucson Electric Power Company

Q. What revenue increase has been requested by TEP?

A. TEP is requesting an increase in base rate revenues of $109.534 million, or approximately 12 percent over adjusted retail electric revenues at current rates of $909.325 million.[2]

TEP's current rates were established in Decision No. 73912, (June 27, 2013), based on a test year ending December 31, 2011, with rates effective on July 1, 2013.[3]

Revenue Requirement Recommended by Staff

Q. What revenue increase does Staff recommend?

A. Staff recommends a base rate increase of no more than $49.4 million on FVRB.

Test Year

Q. What test year is being used in this case?

A. TEP has based its revenue requirement on a historical test year ended June 30, 2015. Staff's calculations use the same historical test year.

[2] TEP Application, dated November 5, 2015, Schedule A-1, line 16.
[3] TEP Application, dated November 5, 2015, page 2, lines 4-5.

ADJUSTMENTS TO RATE BASE

Q. Have you prepared a schedule that summarizes Staff's proposed adjustments to rate base?

A. Yes. The adjusted rate base is shown on Schedule B and Staff's adjustments to TEP's proposed rate base are provided on Schedule E. A comparison of the Company's proposed rate base and Staff's recommended rate base on Original Cost and Fair Value is shown in the following table.

Table 1: Comparison of TEP's Proposed and Staff's Recommended Rate Base
(Thousands of Dollars)

Description	Company	Staff	Difference
Original Cost of Rate Base	$ 2,104,678	$ 2,078,268	$ (26,410)
RCND Rate Base	$ 3,721,880	$ 3,695,470	$ (26,410)
Fair Value Rate Base	$ 2,913,279	$ 2,886,869	$ (26,410)

Q. Are there any of the Company's rate base adjustments to which Staff is not proposing an adjustment?

A. Yes. Staff is not recommending a modification to the following TEP rate base adjustments:

- Investment Tax Credit
- Delayed Utilization
- Springerville ("SGS") Unit 1 Lease Equity Adjustment
- SGS Leasehold Improvements (continued amortization)
- San Juan Unit 2 (Retirement)
- Asset Retirement Obligation
- Fortis Merger Rate Base Adjustment
- SGS Coal Handling Facilities

Q. To what TEP-proposed rate base elements is Staff recommending adjustments?

A. Staff recommends adjustments to the following rate base elements:

- Post Test Year Plant
- Post Test Year Plant – Renewables
- Sundt Coal Handling Facilities (Retirement)
- Accumulated Deferred Income Tax (ADIT)
- Working Capital
- Depreciation
- Capitalized Long Term Incentive Compensation

Post Test Year Plant

Q. Is the Company requesting recovery for any post-test-year plant?

A. Yes. TEP is requesting inclusion of $61.407 million (Total Company Original Cost) post-test-year plant in rate base. The Company stated that this post-test year would be placed in service as of December 31, 2015, or six months after the end of the test year.

Q. Were all of the post-test-year additions to plant used and useful as of December 31, 2015?

A. While many of the post-test-year plant projects were in service and used and useful as of December 31, 2015, several projects, totaling $17.6 million (Total Company Original Cost), were not in service within six months past the end of the test year as planned by the Company.

Q. Please explain Staff's adjustment E-1 – Post Test Year Plant.

A. Staff is recommending that the 14 post-test-year plant projects that were not in service within six months of the end of the test year not be included in rate base. These projects include those listed in following table:

Table 2: Post Test Year Plant Not In Service as of 12/31/15[4]

Line	Description	Expected In Service Date	Total Company
1	312 Project # D14AD79 Selective Non-Catalytic Reduc	April-16	$ 9,774,013
2	303 Project # D141AFR 2014 Acct Financial Reporting	May-16	2,365,016
3	315 Project # D02AB96 Irv #3 Step Transformer Replmt	Jun-16	1,660,946
4	312 Project # D13SK02 SGS U2 Mercury	May-16	1,075,679
5	362 Project # D14NM15 Volt-Var Pilot Ph1 & 2	Jul-16	553,547
6	312 Project # D13SE01 SGS U1 Mercury	Mar-16	498,459
7	303 Project # D141OSP Oracle Services Procurement	May-16	380,252
8	312 Project # D12AC77 Sundt Condensate tank Piping	Dec-16	277,508
9	315 Project # D08AB07 Sundt U3 MCC Replacement	Jun-16	258,865
10	312 Project # D05AD32 San Juan Various Enviro Projs	Jan-16	220,886
11	311 Project # D13AC90 Sundt Cooling Tower Blowdown	Dec-16	158,920
12	362 Project # D11DD93 NE T2A Swtchgr Replc	Jan-16	131,864
13	362 Project # D09EC02 Wilmot T2 Replacement	See Note A	130,583
14	367 Project # D13LE28 RV- Tangerine West 3rd Fdr Tie	See Note A	112,774
15	Total		$ 17,599,312

Note A: Per Company, these projects will be monitored to ensure they are achieving what is expected, and unitized prior to new rates going into effect

The adjustment reduces ACC original cost rate base by $14.7 million and also has an operating income impact due to a reduction in depreciation and property taxes. Operating income is increased by $941,000.

[4] TEP Response to STF 16.3 (Attachment DHM-4).

Q. Please explain Staff's reasoning behind excluding Post-Test-Year Plant that was not in service by December 31, 2015, as planned by the Company?

A. Staff's reasoning for excluding post-test-year plant that was not in service within six months after the end of the test year as planned is that the integrity of using a test year becomes increasingly blurred as more and more adjustments are made beyond the end of the test year period.

The Company's requested increase is based on a test year period from July 1, 2014, through June 30, 2015. The Company has included certain components of the revenue requirement that are outside the test year. For example, the post-test-year plant adjustment includes plant six months beyond the end of the test year. The Company's adjustment for Post-Test Year Plant – Renewables includes plant expected to be in service 18 months past the end of the test year. Including such post-test year items within the revenue requirements can result in a mismatch of the components of the revenue requirements. For plant in service, the mismatch could be in additions to plant that generate additional revenue that is not recognized.

Q. Please discuss the test-year concept and the matching principle.

A. A test period is a consistent time period used to determine the various components of the revenue requirements equation. The purpose for using a consistent test period is to ensure that the revenue and expense levels are matched with the investment used to serve customers, for example, if a new distribution line is installed to provide electric service to a new residence, the provision of electric service to that new residence results in additional revenues being generated. Another example would be installation of a larger transformer to serve a growing load for a large industrial customer resulting in higher revenues as that additional load is served. Fuel and purchase power costs would also increase and more energy is

produced to serve the additional customers. A third example would be the implementation of a new or upgraded software system that results in more productivity and efficiencies, reducing labor or outside contractors. Changes to plant investments impact other areas of the revenue requirements, including revenues and expenses. It is important to be consistent with a test-period approach to ensure that the matching or synchronization between investments, revenues, and expenses are maintained in deriving the revenue requirement. If the various components are not matched properly, a distortion of the relationship between the various components will result. For example, it would not be appropriate to include post-test-year plant additions that would serve new customers without including the associated expenses and revenues that result from the new customer additions.

Q. Did you review the plant that was placed in service between July 1, 2015, and December 31, 2015, to determine if any of those projects could increase revenues or reduce expenses?

A. Yes. There are several project numbers with single line item descriptions that give the appearance that additional revenue could be derived from the installation of those projects. The following table includes those projects:

Table 3: Post Test Year Plant Installed Between 7/1/15 and 12/31/15 with the Potential for Creating Revenue[5]

Project #	Description	Amount
CBONG01	COMMERICAL NEW BUSINESS	$ 1,204,171
CBONG10	NEW SERVICES	$ 376,105
CBONL84	DISTRIBUTION LINES NEW	$ 142,845
CBONG04	RESIDENTIAL NEW BUSIENSS	$ 1,653,431
CBONG94	NEW BUSINESS REPL AND BETTERMENT	$ 1,448,911
		$ 4,825,463

[5] TEP Response to Staff 3.5a, attachment STF 3.5a TEP additions 7/1/12015 thru 12/31/2015, filtered description for "new" and subtotaled. Not included as an attachment due to size.

Q. Is Staff recommending that these projects be excluded from the Company's post-test-year plant?

A. Not at this time. Many of these project numbers include multiple tasks or installations making it difficult to reconcile to the Company's customer normalization adjustment to revenues. Staff is presenting this information only to reinforce its concern regarding the mismatch that occurs from the Company wanting recovery included for plant installed post-test year but without including the companion revenue that would be generated from that included plant.

Q. What was the Company's argument for the inclusion of post-test-year plant?

A. The Company stated that the Commission has included post-test-year plant in prior cases and that it more closely aligns the recovery of costs with the benefits that are being provided to existing customers. The Company also stated that inclusion of post-test-year plant allows timely recovery of costs necessary to maintain a safe, reliable electric system to mitigate larger rate impacts that result from the use of historical test years combined with little to no increase in sales.[6]

Q. What is Staff's response to the Company's argument for inclusion of post-test year plant in rate base?

A. Staff acknowledges the Company's position to an extent, and that is why Staff recommends including post-test-year plant that is in service within six months past the end of the test year or by December 31, 2015. However, Staff recommends that anything beyond six months that is not in service should be excluded from recovery because it unfairly treats only one side of the concern—recovery—without considering future revenue.

[6] Direct Testimony of Dallas Dukes, page 43.

Post Test Year Plant-Renewables

Q. Please explain Staff's adjustment E-2 – Post Test Year Plant-Renewables.

A. The Company separated post-test-year renewable plant and included it in an adjustment separate from the non-renewable post-test-year plant adjustment previously discussed. The Post Test Year Plant – Renewables requests recovery of $23.8 million (Total Company Original Cost) for renewable projects that are expected to be in service as of December 31, 2016—18 months after the end of the test year. Staff recommends allowing recovery for those renewable projects that are in service as of December 31, 2015, the same six-months-beyond-the-test-year period as recommended for the non-renewable post-test-year plant. Using the same six-month cutoff period for both renewables and non-renewables would result in excluding $18.2 million (Total Company Original Cost). Staff's adjustment reduces rate base by $15.9 million. The projects recommended to be excluded are those listed in the following table:

Table 4: Post Test Year Plant-Renewables Not In Service as of 12/31/15[7]

Line	Description	Expected In Service Date	Total Company Post Test Year $
1	344 Project No. D14PD43 Brt Buildout Plan Ft Huachuca Phase II	6/15/16	$ 8,200,000
2	344 Project No. NA TEP Community Solar-Prima Cnty	9/20/16	10,000,000
3	Total		$ 18,200,000

Q. What is Staff's reasoning for recommending these renewable projects be excluded?

A. Staff's reasoning for excluding these renewable projects is the same as for the non-renewables discussed earlier. However, there is an additional concern associated with these two renewable projects. The costs for these two projects are not known and measureable. The Company stated that their cost was estimated by taking the projects' 5 MWs times $2 per

[7] TEP Response to UDR 1.001 – Rate Base-Post Test Year Plant Renewables (Attachment DHM-6).

watt. The estimated cost for the Buildout Plan Ft Huachuca Phase II was further reduced by $2 million savings on the intersection already built in Phase 1.[8] The Company is requesting inclusion of $18.2 million in rate base that is not anticipated to be in service for more than a year after the end of the test year and that is based on a rule-of-thumb cost estimate. Staff recommends that these two projects be excluded from rate base.

Q. Is there an operating income impact to excluding the Post-Test Year – Renewables?

A. Yes, removing these two projects would reduce depreciation and property taxes, resulting in an increase in operating income of $383,000.

Sundt Coal Handling Facilities (Retirement)

Q. Please explain Staff's adjustment to rate base identified as adjustment E-3 – Sundt Coal Handling Facilities (Retirement).

A. This adjustment rectifies the incorrect ACC Jurisdictional allocation applied by the Company in its Application. The oversight was identified during discovery by the Company.[9] The adjustment increases jurisdictional rate base by $20,000.

Accumulated Deferred Income Taxes

Q. Please explain Staff's adjustment to rate base identified as adjustment E-4 – ADIT – Bonus Depreciation.

A. This adjustment recognizes the impact of the extension of bonus depreciation included in H.R. 2029 signed into law by President Obama on December 18, 2015. Bonus depreciation results in a deferral of federal income taxes and is recognized in a rate case through

[8] TEP Response to STF 3.6 (Attachment DHM-7).
[9] TEP response to RUCO 6.4 (Attachment DHM-8) and UDR 1.001 Rate Base-Sundt Coal Handling Facilities-Revised with added totals (Attachment DHM-9).

Accumulated Deferred Income Taxes ("ADIT"). The adjustment reduces rate base by $12.8 million.

Q. Please elaborate.

A. The Protecting Americans from Tax Hikes ("PATH") Act of 2015 allows a bonus depreciation percentage of 50 percent for properties placed in service during 2015, 2016, and 2017, but then phases down to 40 percent in 2018 and to 30 percent in 2019 (for tax purposes). Prior to the passing of the Act, bonus depreciation was set to expire.

ADIT recognizes the difference between what would be included in the Company's books and records for financial reporting purposes and what is recorded for federal and state tax purposes. Bonus depreciation is typically the largest contributor to ADIT.

Q. Does the Company agree with this adjustment?

A. Yes. The Company prepared the calculation that resulted in a revision to the Company's as-filed ADIT balances.[10]

Working Capital

Q. Please explain Staff adjustment E-5 – Working Capital.

A. The Company's proposed rate base includes Working Capital, which is comprised of Cash Working Capital, Fuel Inventory, Materials and Supplies, and Prepaids. Staff's adjustment to Working Capital has several components: (1) corrects the Cash Working Capital calculations formula for Payroll Taxes identified by the Company during discovery; (2) updates the revenue and expense components of the Company's lead-lag study to reflect Staff's adjustments that are discussed within this testimony; (3) removes the materials and supplies

[10] TEP response to AECC 1.3 (Attachment DHM-11).

related to the early retirement of the Sundt Coal Handling Facilities and the expected removal of San Juan Unit 2 from service in December 2017; and (4) removes the prepaid portion of D&O insurance that should be shared 50/50 with shareholders and ratepayers. Staff's adjustment to Working Capital increases jurisdictional rate base by $7.94 million.

Q. Please explain Staff's adjustment to correct the Cash Working Capital calculations formula for Payroll Taxes.

A. Staff identified a significant variance in payroll taxes included in the Cash Working Capital included in this proceeding from what was included in the prior rate case and requested an explanation. The Company identified a formula error in the current 2015 rate case payroll tax number[11] and provided a corrected amount.[12] Staff has incorporated this correction in its Cash Working Capital adjustment.

Q. Please explain Staff's adjustment to update the revenue and expense components of the Company's lead-lag study to reflect Staff's adjustments.

A. Cash Working Capital was developed through the preparation of a lead-lag study. The lead-lag is applied to each component of cost of service to quantify the Cash Working Capital requirement associated with that cost of service item. The Cash Working balance must be updated to reflect Staff's adjustments.

Q. Is the Company's lead/lag study reasonable and in compliance with past Commission preferences?

A. Yes. The Company's lead/lag study is consistent with past cases.

[11] TEP response to STF 10.02 (Attachment DHM-15).
[12] TEP response to STF 14.01 (Attachment DHM-16).

Q. Please explain Staff's adjustment to Working Capital regarding materials and supplies (M&S).

A. TEP's filing reflects the early retirement of the Sundt Coal Handling Facilities and the expected removal of San Juan Unit 2 from service in December 2017. Both units will have an inventory of materials and supplies that cannot be used elsewhere. TEP proposed to record this remaining inventory to a regulatory asset and amortize the cost over a three-year period, starting in the test year. Staff recommends accepting the Company's proposal. However, the Company inadvertently failed to make an adjustment to reduce Working Capital to reduce the costs associated with this unusable inventory.[13] Staff's adjustment reduces Working Capital by $5.1 million.

Q. Please explain Staff's adjustment to Working Capital regarding Prepaid D&O Insurance.

A. This adjustment removes one-half of the prepaid D&O Liability Insurance the Company included within Working Capital. The adjustment is made to be consistent with the adjustment to D&O Liability Insurance expense discussed later. The adjustment reduces Working Capital by $21,000.

Depreciation

Q. Please explain Staff's adjustment to rate base identified as adjustment E-6 – Depreciation.

A. This adjustment to rate base is a companion adjustment to Accumulated Depreciation to Staff's recommended revisions to the Company's new depreciation accrual rates presented by Staff Witness Roxie McCullar. The adjustment increases rate base by $9.2 million.

[13] TEP Response to STF 7.21 (Attachment DHM-14).

Capitalized Long Term Incentive Compensation

Q. Please explain Staff's adjustment to rate base identified as adjustment E-9 Long Term Incentive Compensation.

A. This adjustment transfers the capitalized portion of the Long Term Incentive Compensation program available to executive officers to the Company's shareholders. The Company recorded the amount to Federal Energy Regulatory Commission ("FERC") account 107 Construction Work in Progress, which Staff has interpreted to be included in rate base through the Company's Post Test Year Plant adjustment. The adjustment is discussed later in the Adjustments to Operating Income. The adjustment reduces rate base by $180,098.

ADJUSTMENTS TO OPERATING INCOME

Q. Have you prepared a schedule that summarizes Staff's proposed adjustments to Operating Income?

A. Yes. The adjusted operating income is shown on Schedule C, and the adjustments to TEP's test year revenue and expenses are shown on Schedule E. A comparison of the Company's proposed operating income and Staff's recommended operating income is shown in the following table:

Table 5: Comparison of TEP's Proposed and Staff's Recommended Operating Income (Thousands of Dollars)

Description	Company	Staff	Difference
Revenues	$ 941,031	$ 941,031	$ -
Expenses	$ 842,650	$ 827,063	$ (15,587)
Operating Income	$ 98,381	$ 113,968	$ 15,587

Q. Are there any of the Company's operating income adjustments to which Staff is not proposing an adjustment?

A. Yes. Staff is not recommending a modification to the following TEP Operating Income adjustments:

- Base Cost of Fuel and Purchased Power
- Transmission Expense
- REST and DSM
- Springerville Units 3 and 4
- Lost Fixed Cost Revenue (LFCR)
- Gila O&M
- Customer, Weather, and Unbilled Revenues
- Property Tax Expense
- Environmental Cost Adjustor
- Post Retirement Benefits
- San Juan Unit 1 SCNR O&M
- Power Supply Management
- Injuries and Damages
- Sales of SO2 Allowances
- Bad Debt Expense
- Membership Dues
- TEP Headquarters Retail Space
- Asset Retirement Obligation
- SGS Common Facilities Lease
- Non-Retail and Non-Recurring Revenue
- San Juan Unit 2 Direct Operating Costs
- Fortis Merger Operating Income Adjustment
- Sales for Resale (Power Supply, Purchase Power and Fuel Adjustor Clause ("PPFAC"))

Q. What adjustments is Staff recommending to TEP's proposed Operating Income?

A. Staff is recommending adjustments to the following:

- Depreciation Expense
- Overhaul and Outage Normalization
- Payroll and Payroll Tax Expense

- Long Term Incentive Compensation
- Short Term Incentive Compensation
- Employee Benefits
- Supplemental Executive Retirement Plan (SERP)
- D&O Insurance
- Outside Legal Expense
- Rate Case Expense
- Credit Card Processing
- Interest Synchronization
- Miscellaneous Service Revenue

Depreciation Expense

Q. Please explain Staff adjustment E-6 – Depreciation Expense.

A. The Company is proposing new depreciation rates based on an updated depreciation study performed by Foster Associates. Staff Witness Roxie McCullar is supporting Staff's depreciation adjustment. Staff's adjustment increases operating income by $5.682 million. There is a companion adjustment to accumulated depreciation, increasing rate base by $9.2 million.

Overhaul and Outage Normalization

Q. Please explain Staff adjustment E-7 – Overhaul and Outage Normalization.

A. The Company included an adjustment to normalize the cost of overhauls and outages that do not occur at regular annual intervals. Staff Witness Michael McGarry presents Staff's adjustment. The adjustment increases the Operating Income by $2.551 million.

Payroll Expense and Payroll Taxes

Q. Please explain Staff adjustment E-8 – Payroll and Payroll Taxes.

A. The Company's Payroll adjustment is based on a two-year average of payroll for the twelve months ending June 30, 2014, and June 30, 2015, and reflects known and measureable wage increase for 2016 of two percent and an estimated wage increase for 2017 of two percent.[14]

Payroll taxes reflects the effective tax rate for the Company's Social Security and Medicare taxes that correspondingly increase as a result of the increased expense from the Payroll Expense Adjustment. The Company's effective employer's tax rate for 2015 was applied to the increased payroll expense reflected in the Payroll Expense Adjustment.[15]

Staff's adjustment removes the two percent increase included for 2017. The Company used an estimate that is not known and measureable. Staff's adjustment removes both of these issues. Staff's adjustment increases the Operating Income by $753,000.

Q. Please elaborate on Staff's concern regarding the 2017 pay increase not being known and measureable.

A. The 2017 payroll increase was estimated based on the average union and non-union employees' wage increase for 2015.[16] Additionally, the collective bargaining agreement that was entered into in January 2013 expired in January 2016. The new agreement has not been approved by the IBEW Local 1116 or the IBEW International office.[17] When the Company prepared its adjustment, the 2017 was not known and measureable. Staff's adjustment removes the 2017 increase from the Company's Payroll adjustment.

[14] Direct Testimony of Frank Marino, page 31, lines 17-22.
[15] Direct Testimony of Frank Marino, page 32, lines 6-10.
[16] TEP response to STF 7.4 (Attachment DHM-20).
[17] TEP response to STF 7.8 (Attachment DHM-19).

Long Term Incentive Compensation

Q. Please explain Staff adjustment E-9 – Long Term Incentive Compensation.

A. The Company has a long-term incentive compensation ("LTI") program plan that is delivered in a combination of performance shares and restricted stock units. The program is designed to (1) place a focus on long-term performance, linking a portion of compensation for executive officers to the achievement of multi-year financial results and (2) serve as a retention tool for executive talent.[18] Staff's adjustment transfers the responsibility for funding of the program to the Company's shareholders where it belongs. The adjustment also removes the capitalized portion of Long-Term Incentive Compensation.[19] The adjustment increases the Operating Income by $544,000 and reduces rate base by $180,000.

Q. Please explain why Staff recommends disallowing the long-term incentive compensation program?

A. The performance goals that must be met for the executive officers to receive any LTI are based on financial performance with [redacted].[20] Both of these goals benefit shareholders to the potential detriment of ratepayers; thus these costs should be borne solely by the shareholders.

Short Term Incentive Compensation

Q. Please explain Staff adjustment E-10 – Short Term Incentive Compensation.

A. The Company's short-term incentive compensation, called the Performance Enhancement Pan ("PEP"), is available to all non-union employees. The Company's adjustment reflects an

[18] Direct Testimony of Frank Marino, page 40 line 26-page 41, line 3.
[19] TEP response to RUCO 5.2 (Attachment DHM-21).
[20] [redacted]

average of the PEP expense for the Test Year and the prior year ended June 30, 2014, with two percent increases through 2017. The Company has included 100 percent of the costs. The Company's adjustment also includes the payroll tax component. The Company's adjustments bring the total incentive compensation to $9.2 million (including payroll taxes).[21]

Staff's adjustment includes several pieces: (1) eliminated the two percent increase in 2017 as not known and measureable; (2) the cost was shared 50/50 between shareholders and ratepayers consistent with prior rate cases; and (3) adjusted payroll taxes to correspond with Staff's recommendations. Staff's adjustment increases operating income by $2.2 million.

Q. Please explain Staff's adjustment to eliminate the two percent increase in 2017 as not known and measureable.

A. Consistent with Staff's recommendation for Payroll Expense, the 2017 adjustment should be excluded as not known and measureable as it is based upon an estimate.[22]

Q. Please explain Staff's adjustment to share 50/50 short-term incentive compensation between shareholders and ratepayers, consistent with prior rate cases.

A. Incentive compensation programs can provide benefits to both shareholders and ratepayers. The removal of 50 percent of the Incentive Compensation expense provides an equal sharing of those costs and provides an appropriate balance between the benefits attained by both shareholders and ratepayers.

[21] TEP response to UDR 1.001 Income-Incentive Compensation, page 2 "2 Yr. Average" $8,606,720 plus payroll taxes $554,739 and $11,461 (Attachment DHM-24).
[22] TEP response to STF 11.14 (Attachment DHM-26).

Q. Please describe the Company's Incentive Compensation Program.

A. All TEP non-union employees participate in TEP's PEP, which is tied to annual compensation. The following table lists the financial and other metrics for the Company's 2015 short-term incentive compensation program:

Table 6: TEP's 2015 PEP Goals[23]

Metric	Criteria	Weighting	Benefit to Customers
Net Income	Actual Net Income	40%	Efforts to increase net income result in lower rates
Operation and Maintenance ("O&M") Expenses	Actual O&M expense	20%	Lower O&M expense which results in lower rates
Equivalent Availability Factor ("EAF")	Percentage of time that a generation unit is available to provide power at its maximum rating	10%	Increased generation reliability which reduces purchased power costs
System Average Interruption Duration Index ("SAIDI")	Average number of minutes of interruption experienced by customers	10%	Reduced length of outages
Customer Satisfaction	As measured by J.D. Power surveys	10%	Increased customer satisfaction
OSHA Recordables	OSHA Recordable Incident Rate	10%	Improved employee, customer and community safety

In discovery, the Company summarized the 2015 Short-Term Incentive Compensation goals as

- Financial – 60 percent
  - Net Income – 40 percent
  - Managing Long-term O&M – 20 percent
- Excellent Operations and Safe Work Environment – 40 percent[24]

[23] Direct Testimony of Frank Marino, page 36, lines 1-13.
[24] TEP's response to UDR 1.034 (Attachment DHM-25).

The Company stated, "The Compensation Committee selected the goals and individual weights for the 2015 PEP to ensure an appropriate focus on profitable growth and expense control, as well as operational and customer service excellence, and process improvements. This balanced scorecard approach encourages all employees to work toward common goals that are in the interests of UNS Energy's various stakeholders."[25]

The scores from each goal are totaled and then multiplied by the target bonus of each employee to determine the total available dollars to be paid out. Target bonus percentages, as a percent of base salary, range from 9 to 12 percent for unclassified employees and from 20 to 25 percent for senior management level employees.[26]

Q. Is the Company's adjustment for Short-Term Incentive Compensation consistent with prior rate case orders?

A. No. Regarding the 2013 TEP Rate order, the Company states, "The Commission approved an adjustment that reflected only 50 percent for all employees."[27]

Q. What percentage of TEP's short-term incentive was removed in the case prior to the one in 2013?

A. In Commission Decision No. 70628, (December 1, 2008), 50 percent of TEP's PEP incentive compensation was removed to provide for an equal sharing of such costs, which provides an appropriate balance between the benefits attained by both shareholders and ratepayers.

[25] TEP's response to UDR 1.034 (Attachment DHM-25).
[26] TEP's response to UDR 1.034 (Attachment DHM-25).
[27] Direct Testimony of Frank Marino, page 38, lines 1-4.

Q. What is the reason the Company gives for its request to recover 100 percent of its Short-Term Incentive Compensation despite prior Commission orders?

A. The Company stated, "[T]he PEP performance targets are based on factors that are critical to the success of the Company. These targets put a portion of employee's compensation 'at risk,' which, in effect, ties employee performance to the achievement of goals that directly benefit customers. Whether goals are financial or service driven, the customer ultimately benefits from the improved performance associated with the cost of the program."[28]

Q. Does Staff agree that all of the goals "directly benefit customers?"

A. No. Achieving Net Income or profitability goals is a major component of the Company's incentive compensation program. Financial goals are weighted 60 percent of the total incentive metric, with Net Income equal to 40 percent and Managing Long-term O&M equal to 20 percent.

Net Income or profitability increases as expenses are reduced. Reducing expenses drives up Net Income or profitability, increasing Incentive Compensation payouts to management (with potential payouts of 20 to 25 percent for senior-management-level employees) and benefitting shareholders at the expense of ratepayers. For example, taken to an extreme, expenses can be reduced by deferring maintenance (resulting in increased outages) and failing to adequately staff Customer Services to address customer reported outages, inquiries, or complaints.

As the Commission has recognized in the past, ensuring that the competing interests are balanced is important. This balance has been achieved by requiring the sharing of incentive compensation 50/50 between ratepayers and shareholders.

[28] Direct Testimony of Frank Marino, page 38, lines 6-13.

Q. Has Staff previously recommended and the Commission adopted the sharing of short-term incentive compensation between ratepayers and shareholders?

A. Yes. For example, in reaching its conclusions regarding Southwest Gas Corporation's ("SWG") Management Incentive Plan ("MIP"), the Commission stated in part on page 18 of Decision No. 68487:

> We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendation to be a reasonable resolution.

And again in Decision No. 70011, page 27, the Commission stated:

> We believe that Staff's recommendation provides a reasonable balance of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program.

The Commission again accepted Staff's recommendation in Decision No. 70360, page 21:

> Consistent with our finding in the UNS Electric rate case (Decision No. 70011, at 26-27), we believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program ... Given that the arguments raised in the UNS Electric case are virtually identical to those presented in this case, we see no reason to deviate from that recent decision.

Q. Please summarize Staff's recommended adjustment regarding TEP's Short-Term Incentive Compensation Program.

A. Staff's adjustment: (1) eliminated the two percent increase in 2017 as not known and measureable; (2) the cost was shared 50/50 between shareholders and ratepayers consistent with prior rate cases; and (3) adjusted payroll taxes to correspond with Staff's recommendations. Staff's adjustment increases operating income by $2.166 million.

Employee Benefits

Q. Please explain Staff adjustment E-11 – Employee Benefits.

A. Staff's adjustment recognizes the incremental increase in employee benefits for 2016 and 2017. The Company's Pension and Benefits adjustment included the incremental increase for Pension costs but did not include an adjustment for other employee benefits. The Company updated its adjustment to include employee medical, dental, life, and long-term disability insurance and the Company's contribution for the 401(k) plan. The Company used a two percent inflationary rate for the incremental increase in 2016 and 2017.[29] Staff believes that the two percent increase is reasonable as medical costs are a significant part of employee benefits and have increased historically by more than two percent. Staff's adjustment reduces operating income by $321,000.

Supplemental Executive Retirement Plan

Q. Please explain Staff adjustment E-12 – Supplemental Executive Retirement Plan ("SERP").

A. The Company is requesting recovery for its non-qualified or SERP. This plan provides additional retirement benefits beyond what is allowed by the Internal Revenue Code in the Company's qualified pension retirement plans. The SERP is exclusive to the executive

[29] TEP response to STF 7.15 (DHM Attachment-28).

officers and the funding of this benefit should not be borne by the ratepayers. Staff recommends removing SERP from recovery. Staff's adjustment increases Operating Income by $293,000.

Q. Please explain.

A. Ratepayers are already funding the qualified retirement plan costs in rates. This non-qualified pension plan provides benefits to executive officers that are above and beyond the benefits they receive through participation in the qualified pension plans, including the 401(k) plan. If the Company chooses to provide the additional retirement benefits that exceed the IRS limitations on qualified pension plans, then shareholders, not ratepayers, should fund the costs of those additional benefits.

Directors and Officers Liability Insurance

Q. Please explain Staff adjustment E-13 – D&O Liability Insurance.

A. This adjustment removes one-half of the D&O Liability Insurance expense. The removal of one-half of this expense reflects a sharing of this insurance between shareholders and ratepayers. Staff's adjustment increases Operating Income by $15,000.

Q. Why should the cost of D&O Liability Insurance Expense be shared between shareholders and ratepayers?

A. D&O Liability Insurance protects the officers and directors from the costs of a lawsuit. Shareholders benefit from payouts under the policy that would reduce the cost not recoverable from ratepayers. On the other hand, ratepayers benefit because having the insurance improves the ability of the Company to attract and retain qualified directors and officers and enables the directors and officers to make decisions without fear of personal

liability. As a result, it is reasonable for shareholders to bear some of the cost of D&O Liability Insurance.

Q. Was this adjustment made in the last rate case?

A. Yes. Although the revenue requirement in TEP's most recent rate case was settled and approved in Decision No. 73912 (June 27, 2013), Staff's direct testimony prior to settlement recommended sharing the D&O Liability Insurance between consumers and shareholders by reducing it by 50 percent.

Q. Did the Company make an adjustment to D&O Liability Insurance?

A. Yes. The total D&O Insurance is $973,448. The Company removed $923,142 in its Fortis Merger Operating Income Adjustment, leaving a balance for D&O insurance in the test year of $50,306.[30] However, the Company did not make the adjustment to share the remaining expense between shareholders and ratepayers as had been done in the last rate case.

Q. Is there a related adjustment to rate base?

A. Yes, an adjustment was made to remove one half of the prepaid component of the D&O Liability Insurance included within Working Capital as previously discussed.

Outside Legal Expenses

Q. Please explain Staff adjustment E-14 – Outside Legal Expenses.

A. The two co-owners of the SGS Unit, both of whom were former lessors under a long-term lease with TEP, filed various legal actions against the Company and failed to pay TEP for their share of the operating and capital costs of SGS Unit 1 since the lease expired on January 1, 2016.[31] The Company incurred $1,340,437 in outside legal expenses[32] to defend its

[30] TEP response to STF 7.18 (Attachment DHM-30).
[31] Direct Testimony of Kentton Grant, page 33, line 23-page 34, line 1.

position. These costs are non-recurring expenses and should not be included for recovery through base rates. Staff recommends that the outside legal expenses associated with the co-owners and former lessors of Springerville Unit 1, included in the test year, be removed. The adjustment increases the Operating Income by $828,000.

Q. What is the current status of the legal dispute between TEP and the SGS Unit 1 co-owners?

A. On February 29, 2016, TEP entered into an agreement with the third-party co-owners to purchase their undivided 50.5 percent interests in Unit 1. Upon completion of the purchase, all outstanding disputes and pending litigation and arbitration proceedings between TEP and the third-party owners will be dismissed with prejudice.[33] Additional detail is provided in the section labeled Springerville ("SGS") Unit 1 in this testimony.

Q. Did the settlement include any reimbursement for TEP's legal costs?

A. No. As discussed later in this testimony, third-party owners will pay TEP $12.5 million for operating costs related to Unit 1 incurred on behalf of the third-party owners.[34]

Rate Case Expense

Q. Please explain Staff adjustment E-15 – Rate Case Expense.

A. The Company has included an estimate for incremental outside service rate case expense in its revenue request that initially totaled $1.19 million and was later updated to an estimated $1.21 million.[35] Staff recommends that this amount be reduced as the total amount is excessive and would represent an unreasonable burden on ratepayers. The Company did not

[32] TEP response to AECC 10.1 (Attachment DHM-31).
[33] TEP response to STF 13.2 (Attachment DHM-41).
[34] TEP response to STF 13.2 (Attachment DHM-41).
[35] TEP response to STF 8.1 (Attachment DHM-35).

use a competitive bidding process for the procurement of these outside services.[36] Using no-bid contracts likely drove the costs up. It should also be noted that the Company's request is for outside services, beyond what is provided by TEP's internal labor.

Q. How does the Company's request in this proceeding compare to the allowance from prior cases?

A. In both of TEP's prior base rate cases, Docket Nos. E-01933A-05-0650 and E-01933A-12-0291, the allowance for rate case expense was based on a total amount of $900,000[37] normalized over a four-year period, for an annual recovery of $225,000 per year. The Company's request in this proceeding is a 34 percent increase.

Q. What is Staff's recommendation for an allowance for rate case expenses?

A. Staff recommends an annual allowance of $225,000 per year based on holding the incremental outside services rate case expense to $900,000, normalized over the same four-year base filing cycle that was used in TEP's last base rate case. Staff's adjustment increases the Operating Income by $89,000.

Credit Card Processing

Q. Please explain Staff adjustment E-16 – Credit Card Processing Fees.

A. The Company is proposing to include the majority of the cost associated with providing credit card payment service within its cost of service.[38] Staff's adjustment removes these costs and increases the Operating Income by $2.146 million.

[36] TEP response to RUCO 7.19 (Attachment DHM-34).
[37] TEP response to RUCO 5.4 (Attachment DHM-36).
[38] Direct Testimony of Dallas Dukes, page 58, lines 4-5.

Q. Who currently pays for the cost of customers that use credit cards to pay their bills?

A. All of the third-party transaction fees associated with credit card payments are paid directly to the third-party vendor by the customer making the payment.

Q. What is the Company's proposal?

A. The Company is requesting to reduce the costs charged to credit-card-paying customers from $3.50 per credit card transaction to $1.00 per transaction, limited to one transaction per month for up to $700. The remaining costs of providing this service would be included in rates.[39]

Q. Why does Staff oppose the Company's proposal?

A. There are two reasons that Staff opposes the Company's proposal. First, the Company's proposed change does not significantly reduce the credit card fees that customers' experience. It merely reduces the visibility of the fees. The Company wants to increase expenses—paid by ratepayers—to still cover the full cost of the credit card processing fee. The proposal shifts the burden of some of the credit card costs away from credit-card ratepayers and onto non-credit-card ratepayers. Therefore, not only does the proposed change not significantly reduce costs, it creates a subsidy for credit card customers, while those who do not pay by credit card must share in the cost for the rest of the charge.

Second, the Company's adjustment assumes a significant volume increase in credit card payments. The Company projects a volume increase in credit card payments of 50 percent in the first year of this program and 70 percent over three years. This volumetric increase is based on calculations of independent industry leaders in utility credit card payment

[39] Direct Testimony of Dallas Dukes, page 58, lines 7-10.

processing. This large increase in volume creates an even greater burden for those not paying by credit card.

In summary, Staff opposes the proposed change in recovery of credit card fees because the proposed change is a deceptive move that results in no savings for ratepayers as a whole and increased burden for non-credit-card-paying customers.

Interest Synchronization

Q. Please explain Staff adjustment E-17 – Interest Synchronization.

A. The interest synchronization adjustment synchronizes the rate base and cost of capital with the tax calculation. The adjustment applies the weighted cost of debt to the calculation of test year income tax expense. The result is an adjustment to the amount of synchronized interest included in the tax calculation. The adjustment reduces the Operating Income by $483,000.

Miscellaneous Service Fees

Q. Does Staff recommend any other adjustments to Operating Income?

A. Possibly. The Company has revenue associated with Service Fees that will need to be trued up based on the final rate design.

Miscellaneous Expenses

Q. Did Staff review any other expense items that were not adjusted by the Company during its analysis?

A. Yes. Staff reviewed various expenses, including those within the Company's miscellaneous expenses accounts. Staff found a number of items that required additional discovery to fully

understand whether they were appropriately included within the Company's revenue request.[40]

Q. Does Staff recommend any adjustments associated with this review of miscellaneous expenses?

A. No.

SGS UNIT 1

Q. Please elaborate on the recent developments regarding SGS Unit 1.

A. In January 2015, TEP became the owner of 49.5 percent of SGS Unit 1. On February 29, 2016, well after the Company filed its application, TEP entered into an agreement with the third-party co-owners to purchase their undivided 50.5 percent interests in Unit 1 for $85 million. The transaction is subject to, among other things, FERC approval and satisfaction of other customary closing conditions.[41] The Company expects the purchase of Unit 1 to close in the second quarter of 2016.[42]

Q. What was the situation prior to the signing of this agreement?

A. Prior to the agreement, the two co-owners of SGS Unit 1,[43] both of whom were former lessors under a long-term lease with TEP, filed various legal actions against the Company and have failed to pay TEP for their share of the operating and capital costs of SGS Unit 1 since the lease expired in January 1, 2016.[44] Through March 2016, the co-owners owed TEP $28.9 million in operating costs and $6.5 million in capital costs.[45]

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[40] TEP response to STF 18.2 (Attachment DHM-38).
[41] TEP response to STF 13.2 (Attachment DHM-41).
[42] TEP response to STF 13.3 (Attachment DHM-42).
[43] SGS Unit 1 undivided interest co-owner: Alterna Springerville LLC, an affiliate of Alterna Capital Partners, owns 43.0693 percent and LDVF1 TEP LLC, an affiliate of the Fortress Investment Group owns 7.4257 percent. Source: TEP response RUCO 9.10 (Attachment DHM-46).
[44] Direct Testimony of Kentton Grant, page 33, line 23-page 34, line 1.
[45] TEP response to RUCO 9.09g (Attachment DHM-45).

Q. Will the third-party owners pay any of the unpaid operating and capital costs as part of this agreement?

A. The third-party owners will pay TEP $12.5 million for operating costs related to Unit 1 incurred on behalf of the third-party owners.[46] The Settlement does not include any reimbursement for the outside legal expenses.[47]

Q. What does the Company intend to do with the unreimbursed O&M costs?

A. The Company stated the unreimbursed O&M costs will be written off.[48]

Q. How has the Company treated SGS Unit 1 in it requested recovery?

A. In the Company's initial application, the Company included an adjustment to remove the co-owners' portion of the operating costs from O&M expenses and was proposing to recover the co-owners 50.5 percent share of O&M costs through the PPFAC, commencing on the effective date of the Commission's rate order.

Q. Has the Company modified its requested recovery with the pending purchase of SGS Unit 1?

A. The Company stated that the proposal to recover the co-owners 50.5 percent share of O&M costs through the PPFAC, which predated TEP's agreement to purchase the 50.5 percent share, stated that PPFAC recovery would apply only if the generating capacity was available to meet retail customer demand. The Company still supports this recovery method but is also amenable to O&M recovery through non-fuel rates.[49]

[46] TEP response to STF 13.2 (Attachment DHM-41).
[47] TEP response to STF 18.1 (Attachment DHM-32).
[48] TEP response to RUCO 9.09h (Attachment DHM-45).
[49] TEP response to STF 17.05 (Attachment DHM-43).

Q. What is Staff's recommendation regarding the Company's plans?

A. Staff's witness, Michael McGarry, will address the Company's initial proposal regarding recovery of SGS Unit 1 O&M costs through the PPFAC as initially proposed by the Company. In regard to the Company's statement that it is amenable to O&M recovery through non-fuel rates, the Company has not provided any comprehensive analysis on the potential impact of the settlement and purchase of SGS Unit 1 on rate base, (including additions to plant in service for the acquired undivided interests and treatment of leasehold improvements recorded as a regulatory asset that are currently being amortized[50]), O&M costs (including amounts to be written off), depreciation, fuel, and even who will get the energy. Therefore, Staff is not proposing an adjustment at this time.

FORTIS ACQUISITION COSTS

Q. Did the Company address the rate-case-related conditions in the Fortis/UNS Energy merger settlement agreement?

A. There were 66 settlement conditions within the Settlement Agreement that the Commission approved in Docket Nos. E-04230A-14-0011 and E-01933A-14-0011 in Decision No. 74689 (August 12, 2014). The Company's direct testimony identified and reported on its compliance to 13 settlement conditions as they relate to this rate case. There are two other conditions (i.e., 28 and 29) regarding best efforts to maintain or improve quality of service. The Company will report on its compliance with the other settlement conditions in an annual compliance filing, with the first such annual report due April 1, 2016.[51]

Q. Which Settlement Conditions did the Company address related to the rate case in this filing?

A. The Company addressed the following Merger Conditions.

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[50] TEP response to STF 17.06 (Attachment DHM-44).
[51] Direct Testimony of Frank Marino, page 46, lines 12-16).

- Condition 5: The Company is not seeking recovery of or on any acquisition premium or goodwill amount in this rate proceeding.
- Condition 6: The revenue requirement does not include any allocated Fortis costs.
- Condition 7: The revenue requirement does not include costs for shareholder litigation related to the merger to ratepayers.
- Condition 8: The revenue requirement does not include recovery of or on the transaction and transition costs associated with the merger.
- Condition 8 (additional element): The revenue requirement does not include recovery of any Change of Control and Retention payments related to the merger.
- Condition 9: The revenue requirement does not include impacts of any fluctuations in foreign exchange rates and any incremental taxes arising from its international ownership structure.
- Condition 10: Fortis has not made an acquisition since the approval of the Fortis/UNS Energy merger that has had any material adverse impact on UNSE.
- Condition 11: Revenue requirement in this case does not include any increase in the total compensation of the Senior Management Personnel. At the end of the test year there were 10 executive officers of UNS Energy. This is one fewer than the number of executive officers as of August 12, 2014, the date of Decision No. 74689, approving the merger. Therefore, pursuant to Condition 11, the portion of compensation for those Senior Management Personnel that is allocable to TEP has not increased.
- Condition 12: Fortis has not completed any merger or acquisition within the United States since the approval of the Fortis/UNS Energy merger.
- Condition 13: Goodwill and transaction costs of the merger have been excluded from the rate base, expenses, and capitalization in the determination of rates and earned returns of TEP.

- Condition 15: The revenue requirement does not reflect any recovery or recognition in the determination of rate base of any legal or financial advisory fees or other external costs associated with the merger.
- Condition 17: The capital structure in this docket is separate from that of Fortis. The Company has used UNS Electric's actual capital structure in this rate case.
- Condition 62: TEP relies in whole or in part on Fortis for the following items. First, while TEP continues to raise debt capital funds through its in-house treasury function, equity capital financing is performed entirely by Fortis. The costs incurred by Fortis for this function are allocated to UNS Energy and TEP and those costs incurred during the Test Year have been removed. Second, TEP coordinates with Fortis on procuring the majority of its insurance coverage to take advantage of scale discounts that would otherwise be unavailable to TEP. TEP contracts with the insurance broker directly and is direct charged for such coverage.[52]

Q. Is the Company in compliance with the settlement conditions that it reported on in this proceeding?

A. Yes. However, as discussed by Staff Witness David Parcell, there are possible downgrades of Fortis and TEP securities in connection with the proposed acquisition of the ITC Holdings Corp. Staff has reserved the right to comment on whether this would result in a material adverse impact and violate Condition 10.

In addition, the Company justified its compliance to Condition 11 based upon the number of officers as opposed to the change in total compensation. Condition 11 states, "The Regulated Utilities shall not include in the revenue requirements any increase in the total compensation of Senior Management Personnel (the 11 executives at the date of closing) in

[52] Direct Testimony of Frank Marino, page 46, line 9 – page 49, line 24.

any rate increase request using a test year ending December 31, 2017, or earlier. If the number of Senior Management Personnel in a test year ending December 3, 2017, or earlier is less than 11, the aforementioned total compensation will be reduced appropriately." [Emphasis added][53] The Company stated that at the end of the test year there were 10 executive officers of UNS Energy. This is one fewer than the number of executive officers as of August 12, 2014, the date of Decision No. 74689, approving the merger. Therefore, pursuant to Condition 11, the portion of compensation for those Senior Management Personnel that is allocable to TEP has not increased.[54]

During the test year the number of officers were reduced to ten.[55] However, at the date of the filing, there were once again 11 officers.[56] Staff believes that compliance to Condition 11 should also consider total compensation before the merger and the total compensation requested by the Company in this rate case. Staff found that total adjusted officer compensation included within the test year is less than the total compensation prior to the merger.[57] The Company is in compliance with Condition 11.

While the Company is in compliance for the settlement conditions that it reported on in this proceeding, as discussed by Staff Witness David Parcell, there are possible downgrades of Fortis and TEP securities in connection with the proposed acquisition of the ITC Holdings Corp. Should these downgrades occur, Staff has reserved the right to comment on whether this would result in a material adverse impact and violate Condition 10.

[53] Docket Nos. E-04230A-14-0011 and E-01933A-14-0011, Decision No. 74689, Exhibit A-Settlement Agreement, page 2.
[54] Direct Testimony of Frank Marino, page 48, lines 8-15.
[55] TEP response to AECC 13.2 (Attachment DHM-40).
[56] TEP response to AECC 13.3 (Attachment DHM-39).
[57] TEP response to AECC 13.1, Confidential Attachment (Confidential Attachment DHM-47).

Q. Does this conclude your direct testimony?

A. Yes.

Professional Experience and Education of Donna H. Mullinax

Summary

Mrs. Mullinax has over thirty-six years of financial, management and consulting experience. She is President of Blue Ridge. Prior to assuming the role as President, she held the position of Vice President and Chief Financial Officer for the last 20 years and served on various Boards of Directors. She has extensive experience in project management; regulatory and litigation support; financial, administration, and human resource management. She has performed numerous financial, compliance and management audits. Mrs. Mullinax has excellent analytical skills and report writing capabilities. She has designed and implemented accounting and business systems and developed policy and procedure manuals to support those systems.

Key Qualifications and Selected Professional Experience

Financial, Administration, and Human Resource Management

As Chief Financial Officer and Vice President she is responsible for all aspects of financial, administration, and human resources. Her responsibilities include accounting, cash management, budgeting, tax planning and preparation, fixed assets, human resources, and employee benefits. Records under her control have been subject to an IRS compliance audit with no findings.

Project Management

Mrs. Mullinax has successfully managed numerous projects controlling cost, schedule, and scope. These projects included management, financial, and compliance audits, M&A due diligence reviews, economic viability studies, prudence reviews, and litigation/regulatory support for construction contract claims and regulatory proceedings. She works well with diverse team members and has an excellent ability to reconcile various viewpoints and establish and maintain effective working relationships among cross-functional teams.

Financial, Compliance, and Management Auditing

Mrs. Mullinax is a skilled auditor. She has performed numerous financial, compliance, and management audits for governmental entities, businesses, and public utilities. As a CPA and CIA, she is knowledgeable about sound internal control processes and procedures and has made numerous recommendations for modifications to provide reasonable assurance regarding the achievement of objectives related to (1) effectiveness and efficiency of operations; (2) reliability of financial records, and (3) compliance with laws and regulations.

She has also conducted detailed base rates revenue requirements and rider compliance audits. She has analyzed financial information and budget projections, performed risk identification, and evaluated performance against industry benchmarks. Her extensive professional experience allows her to effectively analyze and evaluate methods and procedures and to thoroughly document her findings. She has successfully testified to her audit findings.

- Before the Nebraska Public Service Commission (NEPSC) on behalf of the Public Advocate of Nebraska
  - NEPSC Application NG-0072.01, SourceGas Distribution, LLC May 2014-August 2014.

Professional Experience and Education of Donna H. Mullinax

- NEPSC Application No. NG-0074, Black Hills/Nebraska Gas Utility Company, LLC, d/b/a Black Hills Energy, July-November 2013.
- NEPSC Application No. NG-0072, SourceGas Distribution, LLC March 2013-May 2013.

Project Manager and Lead Auditor. Led the review of the Companies' applications for an infrastructure system replacement cost recovery charge for compliance to the Nebraska Natural Gas Regulation Act. The reviews included a detailed mathematical verification and validation of support for the revenue requirements model and reviews of plant work order supporting the requested recovery of utility plant in service. Summarized the transactional testing results and calculated the impact to the customer charge. Drafted the report including documentation of findings, conclusions, and recommendations and coordinated the accumulation of work papers to thoroughly support all work.

❖ On behalf of the Staff of the Public Utilities Commission of Ohio (PUCO)

- Case No. 16-0021-EL-RDR: Distribution Investment Rider (DIR) Audit of Columbus Southern Power Company and Ohio Power Company, d/b/a AEP-Ohio, March 2016-Present. Project Manager and Lead Auditor.
- Case No. 15-1739-EL-RDR: Delivery Capital Recovery (DCR) Rider Audit of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively, Companies), December 2016-March 2016. Project Manager and Lead Auditor.
- Case No. 14-1929-EL-RDR: Delivery Capital Recovery (DCR) Rider Audit of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively, Companies), December 2015-March 2015. Project Manager and Lead Auditor.
- Case No. 13-2100-EL-RDR: Delivery Capital Recovery (DCR) Rider Audit of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively, Companies), December 2013-March 3013. Project Manager and Lead Auditor.
- Case No. 13-0419-EL-RDR: Distribution Investment Rider (DIR) Audit of Columbus Southern Power Company and Ohio Power Company, d/b/a AEP-Ohio, March-August 2013. Project Manager and Lead Auditor.
- Case No. 12-2855-EL-RDR: Delivery Capital Recovery (DCR) Rider Audit of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively, Companies), December 2012-July 2013. Project Manager and Lead Auditor.
- Case No. 11-5428-EL-RDR: DCR Rider Audit of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively, Companies), November 2011 - May 2012. Project Manager and Lead Auditor.

Led the review to ensure the accuracy and reasonableness of the Companies' compliance with its Commission-approved infrastructure cost recovery rider filings. The review included a detailed mathematical verification and validation of the support of the riders' revenue requirements model, development of sensitivity analysis that supported the PPS sampling techniques used to isolate specific plant work order for further testing. Summarized the transactional testing results and calculated the impact to the rider's revenue requirements. Detailed variance analyses of historical data with investigations into any significant changes. Drafted the report including documenting findings, conclusions, and recommendations and

coordinated the accumulation of work papers to thoroughly support all work performed.

- Case # 08-0072-GA-AIR Columbia Gas of Ohio for an increase in gas rates, April-August 2008
- Case # 07-0829-GA-AIR Dominion East Ohio for an increase in gas rates, November 2007-July 2008
- Case # 07-0589-GA-AIR Duke Energy Ohio for an increase in gas rates. November 2007-Februrary 2008

Lead Auditor and assistant project manager. Performed a comprehensive rate case audit of companies' gas rate filings to validate the filings, provided conclusions and recommendations concerning the reliability of the information, and supported Staff in its evaluation of the reasonableness of the filing. Drafted the report including documenting findings, conclusions, and recommendations and coordinated the accumulation of work papers to thoroughly document work performed.

❖ On behalf of the Massachusetts Department of Public Utilities, Case No. D.P.U. 08-110, regarding the Petition and Complaint of the Massachusetts Attorney General for an Audit of New England Gas Company (NEGC), February-August 2010. Lead Auditor and Assistant Project Manager. Conducted a management audit on how NEGC manages its accounting and financial reporting functions and whether sufficient controls are in place to ensure that the information included in the company's filings can be reasonably relied upon for setting rates – areas reviewed included general accounting, financial reporting, and internal controls; plant accounting; income tax; accounts receivable; accounts payable; cash management; payroll; cost allocations; and capital structure. Developed the report including documenting findings, conclusions, and recommendations and coordinated the accumulation of work papers to thoroughly document work performed.

❖ On behalf of the Staff of the Connecticut Public Utilities Regulatory Authority (PURA), Docket 07-07-01: Diagnostic Management Audit of Connecticut Light and Power Company, July 2008-June 2009, Lead Auditor and Assistant Project Manager. Performed an in-depth investigation and assessment of the company's business processes, procedures, and policies relating to the management operations and system of internal controls of the company's executive management, system operations, financial operations, marketing operations, human resources, customer service, external relations, and support services. In addition, supported an in-depth review of the development and implementation process of the company's new customer information system. Developed the report including documenting findings, conclusions, and recommendations and coordinated the accumulation of work papers to thoroughly document all findings.

❖ Before the Oregon Public Utilities Commission (ORPUC), Docket No. UP 205: Examination of NW Natural's Rate Base and Affiliated Interests Issues, Co-sponsored between NW Natural, ORPUC Staff, Northwest Industrial Gas Users, Citizens Utility Board, August 2005-January 2006, Lead Auditor and Assistant Project Manager. Examined NW Natural's Financial Instruments, Deferred Taxes, Tax Credits, and Security Issuance Costs to ensure Company compliance with orders, rules, and regulations of the ORPUC and with Company policies. Developed the report including documenting findings, conclusions, and recommendations and coordinated the accumulation of work papers to thoroughly document work performed.

Professional Experience and Education of Donna H. Mullinax

Regulatory and Civil Litigation

She has provided or supported civil or regulatory testimony in Arizona, Colorado, Connecticut, Delaware, Illinois, Maryland, Michigan, Missouri, New York, North Carolina, North Dakota, South Carolina, Texas, and Utah. She has also served as an advisor to public service commissioners in the District of Columbia and Connecticut. In addition to providing analytical support, she has served as an expert witness and routinely works with other highly specialized expert witnesses. She has developed defendable analyses and testimony in connection with rate cases, audit findings, and other regulatory issues. She has also supported various civil litigations including delay and disruption construction claims and financial fraud. She has supported counsel with interrogatories, depositions, and hearings/trials support.

Regulatory Proceedings

- Before the Arizona Corporation Commission on behalf of Staff
  - Docket No. E-024204A-15-0142 UNS Electric, Inc. August 2015-present.

    Project Manager, Lead Auditor, and Expert Witness. Testified to Staff's position regarding the rate base, adjusted net operating income, and revenue requirements proposed by UNS Electric, Inc.
- Before the Nebraska Public Service Commission (NEPSC) on behalf of the Public Advocate of Nebraska.
  - NEPSC Application NG-0078, SourceGas Distribution, LLC May 2014-December 2014.

    Project Manager, Lead Auditor, and Expert Witness. Led the review of the Companies' applications to replace its infrastructure system replacement (ISR) cost recovery charge with a prospective System Safety and Integrity Rider (SSIR). The review included an analysis of the Company's projected revenue deficiency that lead to the request for the prospective SSIR. The SSIR was subject to a detailed mathematical verification and validation of support for the revenue requirements model and reviews of proposed projects supporting the requested recovery of utility plant in service. Testimony on the analysis will be filed in August 2014.
- On behalf of the Commissioners and Staff of the District of Columbia Public Service Commission (DCPSC)
  - Formal Case No. 1103 Potomac Electric Power Company (Pepco) base electric rate case, June 2013-present. Project Manager.
  - Formal Case No. 1093 Washington Gas Light Company (WGL) base gas rates case, July 2011-July 2013. Project Manager.
  - Formal Case No. 1087 Pepco base electric rates case, September 2011-December 2012
  - Formal Case No. 1076 Pepco base electric rates case, July-December 2009
  - Formal Case No. 1053 Pepco base electric rates case, February 2007-June 2008

    Lead Consultant advising Commissioners and Staff of the Office of Technical and Regulatory Analysis regarding Company's proposed rate base, net operating income and revenue requirements. Assessed the companies' and Intervenors' positions on various issues and provided defendable recommendations for the Commissioners' consideration. Developed "what if" revenue requirement model used during Commission deliberations to analyze the impact of various adjustments. Supported the drafting of the Commission's Order and supplied the revenue requirement

schedules to support the final decision. Supported the Commissioners' legal team in addressing motions for reconsideration.

- Formal Case No. 1106 Washington Gas Light Company (WGL) Interruptible Service Customer Class rates and related issues, February 2014-present. Lead Consultant and Project Manager. Led the effort to review the Distribution Charge Adjustment and proposed changes as well as the review of taxes, depreciation, and cash working capital within the customer class cost of service study.
- Formal Case No. 1032 Pepco base electric rates case, January-March 2005. Senior Technical Consultant and Assistant Project Manager. Reviewed and evaluated Company's compliance filings for class cost of service and revenue requirements for distribution service pursuit to a settlement approved in May 2002. Provided analysis and recommended adjustments to Staff. Proceeding was settled in anticipation of a full rate case for rates to be effective August 8, 2007.
- Formal Case No. 1016 WGL natural gas base rates case, June-December 2003. Senior Technical Consultant and Project Manager. Analyzed and recommended adjustments regarding the company's proposed increase to base rates – advised the Commission on party positions during deliberations Review and evaluation of company's depreciation study filed with the Commission.

❖ Before the Missouri Public Service Commission, Case No. HR-2011-0241, on behalf of the City of Kansas City: Veolia Energy Company 2011 and 2012 electric base rates case, July-September 2011. Senior Technical Consultant. Analyzed Company's proposed net operating income, rate base, and revenue requirements. Supported testifying witness with drafted testimony and development of a model to calculate an alternative revenue requirement incorporating recommended adjustments.

❖ Before the North Dakota Public Service Commission, Case No. PU-10-657/PU-11-55: Northern States Power Company (NSP) 2011 and 2012 electric base rates case, April-November 2011. On behalf of the Commission Staff, Lead Consultant and Assistant Project Manager. Led the analysis of NSP's rate increase filings and supported adjustments for the Commission's consideration. Developed a model to calculate the appropriate revenue requirements and exhibits to support Staff recommended adjustments.

❖ Before the Connecticut Public Utilities Regulatory Authority (PURA), Docket 10-02-13: Aquarion Water Company base rates case, on behalf of the PURA, April-August 2010. Senior Technical Consultant and Assistant Project Manager. Reviewed the expense component of the company's revenue requirement and recommended adjustments for Staff consideration.

❖ Before the of the Delaware Public Service Commission on behalf of Staff

- Docket No. 09-414: Delmarva Power & Light Company (DPL) electric base rates case, September 2009-May 2010. Expert Witness and Assistant Project Manager. Analyzed the company's rate increase filings and provided testimony offering adjustments for the Commission consideration related to the rate base and revenue requirements.
- Docket No. 06-284: DPL's gas base rates case, October 2006-March 2007. Senior Technical Consultant and Assistant Project Manager. Analyzed the Company's filings, checked the mathematical accuracy of the Company's revenue requirements calculations, and provided analytical support to testifying witness.

Professional Experience and Education of Donna H. Mullinax

- Before the Michigan Public Service Commission (MIPSC) on behalf of the Michigan Attorney General
  - Case No. U-15506: Consumers Energy Company base gas rates case, May-November 2008. Expert Witness and Assistant Project Manager. Analyzed the company's rate increase filings and provided testimony offering adjustments for the Commission consideration related to the rate base and revenue requirements – proceeding was settled through negotiations.
  - Case No U-15244 Detroit Edison electric base rates case, September 2007-October 2008.
  - Case No. U-15245 Consumers Energy Company base gas rates case, July 2007-April 2008.

    Senior Technical Consultant and Assistant Project Manager. Analyzed the Company's filings, checked the mathematical accuracy of the Company's revenue requirements calculations, and provided analytical support to testifying witness.
  - Case No. U-14547 Consumers Energy Company base gas rates case, December 2005-April 2006. Expert Witness and Assistant Project Manager. Analyzed Company's rate increase filings and provided testimony offering adjustments for Commission consideration related to the rate base and revenue requirements.
- Before the Maryland Public Service Commission (MDPSC)
  - Case No. 9092 Pepco electric base rates case, on behalf of the Staff of the MDPSC, December 2006-June 2007. Expert Witness and Assistant Project manager. Analyzed Company's rate increases filings and provided direct and rebuttal testimony offering adjustments for the Commission consideration related to the rate base and revenue requirements.
  - Case No. 9062 Chesapeake Utilities Corporation gas base rates case, on Behalf of the Maryland Office of People's Counsel, May-August 2006. Expert Witness and Assistant Project Manager. Analyzed Company's rate increase filings and provided testimony offering adjustments for the Commission consideration related to the rate base and revenue requirements – participated in settlement negotiations that were ultimately accepted by all parties.
- Before the Illinois Commerce Commission, Case No. 05-0597, on behalf of the Illinois Citizens Utility Board, Cook County State Attorney's Office and City of Chicago, November 2005-May 2006. Senior Technical Consultant and Assistant Project Manager. Analyzed the Company's filings, checked the mathematical accuracy of the Company's revenue requirements calculations, and provided analytical support to testifying witness.
- Before the Hawaii Public Utilities Commission (HPUC), Docket No. 05-0075: Instituting a Proceeding to Investigate Kauai Island Utility Cooperative's Proposed Revised Integrated Resource Planning and Demand Side Management Framework, On behalf of the Staff of the HPUC, June-November 2005. Senior Technical Consultant and Assistant Project Manager. Conducted and reported on the results of an industry survey of other cooperatives and Commissions to obtain an overview of how other entities approach the specific issues identified within this docket.
- Before the Public Utilities Commission of the State of Colorado (COPUC), Docket No. 04A-050E: Review of the Electric Commodity Trading Operations of Public Service

Professional Experience and Education of Donna H. Mullinax

Company of Colorado (PSCo), On behalf of the COPUC Staff, March-September 2004. Expert Witness and Assistant Project Manager. Performed a transaction audit of PSCo's electric commodity trading operations and submitted testimony describing the process used to conduct the investigation, a summary of the audit findings, and discussion of the significance of the findings.

- Before the New York Public Service Commission, Case No. 00-E-0612: Proceeding on Motion of the Commission to Investigate the Forced Outage at Consolidated Edison Company of New York, Inc.'s Indian Point No. 2 Nuclear Generation Facility, On behalf of Consolidated Edison Company of New York, Inc., October 2000-September 2003. Project Manager. Supervised cross functional teams to assist scheduling and nuclear engineering experts with responses to interrogatories and the development of three comprehensive rebuttal testimonies on the prudence of extended outages at the Indian Point 2 nuclear power plant. The proceeding settled prior to filing of testimony.

Civil Litigation

- ADF Construction vs. Kismet, On Behalf of ADF Construction, December 2003-February 2004. Assistant Project Manager for a delay and disruption construction claim related to a large hotel complex in North Carolina – worked with scheduling experts to determine schedule delay and disruption and calculated related damages.
- On behalf of New Carolina Construction, July 2002-January 2003
  - New Carolina Construction vs. Atlantic Coast
  - New Carolina Construction vs. Acousti

  Project Manager for a delay and disruption claim related to construction of a large high school complex in South Carolina – worked with scheduling experts to determine schedule delay and disruption and calculated related damages. Claim was settled out of court.
- State of Nevada Bureau of Consumer Protection, September-December 2003. Assistant Project Manager for damage assessment project related to potential litigation regarding the Western Market Manipulation.
- Oakwood Homes, On behalf of Oakwood Homes, February 1999-May 2000. Assistant Project Manager for a delay and disruption claim related to the construction of a large manufacturing facility in Texas – worked with scheduling experts to determine schedule delay and disruption and calculated related damages. Dispute was settlement through mediation.
- McMillan Carter, On behalf of McMillan Carter, June-September 2002. Project Manager for a delay and disruption claim related to construction of a large high school complex in North Carolina – worked with scheduling experts to determine schedule delay and disruption and calculated related damages. Claim was settled out of court.
- Fluor Daniel Inc. vs. Solutia, Inc., On behalf of Fluor Daniel, May 2000-August 2001. Assistant Project Manager for a delay and disruption construction claim related to large chemical processing facility in Texas – worked with scheduling experts to determine schedule delay and disruption and calculated related damages. Dispute proceeded through mediation.
- First National Bank of South Carolina vs. Pappas, On Behalf of First National Bank of South Carolina, 1991-1992. Civil litigation, deposed during pre-trial discovery on analytical findings related to check kiting and fraudulent loan applications. Supported counsel and expert witnesses during civil proceeding.

Professional Experience and Education of Donna H. Mullinax

- First Union vs. Pappas, On Behalf of First Union, 1991-1992. Civil litigation, deposed during pre-trial discovery on analytical findings related to check kiting and fraudulent loan applications. Dispute was settled out of court.

Testimony proffered

Before the Colorado Public Utilities Commission
- Public Service Company of Colorado - Docket No. 04A-050E

Before the Delaware Public Service Commission
- Delmarva Power & Light Company - Docket No. 09-414

Before the Maryland Public Service Commission
- Potomac Electric Power Company - Case No. 9092
- Chesapeake Utilities Corporation - Case No. 9062

Before the Michigan Public Service Commission
- Consumers Energy Company - Case No. U-15506
- Consumers Energy Company - Case No. U-14547

Before the Public Service Commission of Nebraska
- SourceGas Distribution LLC – Docket No. NG-0078

System Implementation

Mrs. Mullinax has worked with various business and local governmental entities to design and implement accounting and business systems that addressed real world problems and concerns. She has developed accounting policy and procedure manuals for county governments, a library, and a water utility.

Professional Experience

Blue Ridge Consulting Services, Inc.: 2004 - Present
President
Vice President and Chief Financial Officer
Senior Technical Consultant / Expert Witness

Hawks, Giffels &Pullin, Inc.: 1993 - 2004
Vice President and Chief Financial Officer
Executive Consultant
Controller

Cherry, Bekaert & Holland, CPAs: 1991 - 1993
Accounting Supervisor
Senior Accountant
Staff Accountant

Smith, Kline and French Pharmaceutical Company: 1988 - 1991
Professional Sales Representative

Milliken & Company: 1979 - 1988
Quality Assurance Manager
Technical Cause Analyst
Department Manager

Professional Experience and Education of Donna H. Mullinax

Professional Certification

Certified Public Accountant (CPA), State of South Carolina - 1993
Certified Financial Planner (CFP) - 1994
Certified Internal Auditor (CIA) - 2006
Chartered Global Management Account (CGMA) - 2012

Professional Affiliations

Member of the American Institute of Certified Public Accountants (AICPA)
Member of the South Carolina Association of Certified Public Accountants (SCACPA)
Member of the Institute of Internal Auditors (IIA)
Member of the Western Carolinas Chapter of the Institute of Internal Auditors (WCIIA)

Education

Clemson University, B.S. Administrative Management with honors, 1978
Clemson University, M.S. in Management, 1979
College for Financial Planning, 1994
NARUC Utility Rate School, 32nd Annual Eastern

ARIZONA CORPORATION COMMISSION

Docket No. E-01933A-15-0322

Tucson Electric Power Company
List of Schedules

Line #	Schedule	Description	
1	Schedule A	Computation of Increase in Gross Revenue Requirement	
2	Schedule A.1	Computation of Revenue Conversion Factor	
3	Schedule B	Original Cost and RCND Adjusted Rate Base	
4	Schedule C	Adjusted Net Operating Income	
5	Schedule D	Cost of Capital	
6	Schedule D.1	Impact of Recommended Cost of Captial on Company's Proposed Revenue Requirements	
7	Schedule E	Summary of Staff's Rate Base and Operating Income Adjustments	
8	Schedule E-1	Adjustment E-1	Post Test Year Plant In Service After 12/31/15
9	Schedule E-1 WP	Adjustment E-1	Post Test Year Plant In Service After 12/31/15 Work Paper
10	Schedule E-2	Adjustment E-2	Post Test Year Plant In Service-Renewables In Service After 12/31/15
11	Schedule E-3	Adjustment E-3	Sundt Coal Handling Facilities (Retirement) - ACC Jurisdictional Allocation
12	Schedule E-4	Adjustment E-4	ADIT-Bonus Depreciation
13	Schedule E-5	Adjustment E-5	Working Capital
14	Schedule E-5 WP	Adjustment E-5	Cash Working Capital Workpaper
15	Schedule E-6	Adjustment E-6	Depreciation Expense
16	Schedule E-7	Adjustment E-7	Overhaul and Outage Normalization
17	Schedule E-8	Adjustment E-8	Payroll and Payroll Taxes
18	Schedule E-8 WP	Adjustment E-8	Payroll and Payroll Taxes Workpaper
19	Schedule E-9	Adjustment E-9	Long Term Incentive Compensation
20	Schedule E-10	Adjustment E-10	Short Term Incentive Compensation
21	Schedule E-10 WP	Adjustment E-10	Short Term Incentive Compensation Workpaper
22	Schedule E-11	Adjustment E-11	Employee Benefits
23	Schedule E-12	Adjustment E-12	Supplemental Executive Retirement Plan (SERP)
24	Schedule E-13	Adjustment E-13	Directors and Officers (D&O) Liability Insurance
25	Schedule E-14	Adjustment E-14	Outside Legal Expenses
26	Schedule E-15	Adjustment E-15	Rate Case Expense
27	Schedule E-16	Adjustment E-16	Credit Card Processing Fees
28	Schedule E-17	Adjustment E-17	Interest Synchronization

ARIZONA CORPORATION COMMISSION

Tucson Electric Power Company
Computation of Increase in Gross Revenue Requirement
ACC Jurisdictional
Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Reference	TEP Proposed Original Cost	TEP Proposed RCND	TEP Proposed Fair Value	Staff Calculated Original Cost	Staff Calculated RCND	Staff Calculated Fair Value	Difference Original Cost	Difference RCND	Difference Fair Value
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Adjusted Rate Base	Sch. B (ACC)	$ 2,104,678	$ 3,721,880	$ 2,913,279	$ 2,078,268	$ 3,695,470	$ 2,886,869	$ (26,410)	$ (26,410)	$ (26,410)
2	Required Operating Income (a)		$ 165,898	$ 165,898	$ 165,898	$ 144,418	$ 144,418	$ 144,418	$ (21,480)	$ (21,480)	$ (21,480)
3	Adjusted Orperating Income	Sch. C (ACC)	$ 98,381	$ 98,381	$ 98,381	$ 113,968	$ 113,968	$ 113,968	$ 15,587	$ 15,587	$ 15,587
4	Operating Income Deficiency		$ 67,517	$ 67,517	$ 67,517	$ 30,450	$ 30,450	$ 30,450	$ (37,067)	$ (37,067)	$ (37,067)
5	Gross Revenue Conversion Factor		1.6223	1.6223	1.6223	1.6223	1.6223	1.6223			
6	Increase in Gross Revenue Requirement		$ 109,534	$ 109,534	$ 109,534	$ 49,400	$ 49,400	$ 49,400	$ (60,134)	$ (60,134)	$ (60,134)
9	Weighted Average Cost of Captial	Schedule D	7.34%	7.34%	7.34%	6.68%	6.68%	6.68%			
10	Fair Value Adjustment		0.55%	-2.88%	-1.65%	0.27%	-2.77%	-1.68%			
11	Required Rate of Return	Schedule D	7.88%	4.46%	5.69%	6.95%	3.91%	5.00%			
12	Return on Equity		10.35%			9.35%					
	Revenue Increase and Estimated Percentage Rate Increase (Decrease)										
13	Electric Retail Revenues - Current Rates	Sch. C (ACC)			$ 909,303			$ 909,303	Staff Revenue from Schedule C		
14	With Proposed Base Rate Increase	Line 6 + Line 10			$ 1,018,837			$ 958,703			
15	Percent Retail Revenue Increase				12.0%			5.4%			

Notes and Source
Column C and D: TEP filing, Schedule A-1

		TEP Proposed	
[a]	Required Operating Income		
	Adjusted OCRB Rate Base	$ 2,104,678	
	Weighted Average Cost of Captial	7.34%	
	Required Income Before FV Adjustment	$ 154,421	$ 154,421
	Adjusted FV Rate Base	$ 2,913,279	
	Adjusted OCRB Rae Base	$ 2,104,678	
	Difference	$ 808,601	
	Return on FV Increment (b)	1.42%	
	Required Income on FV Increment	$ 11,482	$ 11,482
	Required Operating Income		$ 165,898

(b) From 2015 TEP Rev Req Model.xlsm; Cover; Line 33

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Schedule A.1
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Tucson Electric Power Company
Computation of Revenue Conversion Factor

Test Year Ended June 30, 2015

Line	Description	Company Proposed	Staff Adjustment	Staff Proposed
	(A)	(B)	(C)	(D)
1	Gross Revenue	100.00%		100.00%
2	Less: Uncollectible Revenue (a)	0.1896%		0.1896%
3	Taxable Income as a Percent	99.81%		99.81%
4	State Income Tax Rate [b]	4.99%		4.99%
5	Federal Effective Income Tax Rate [c]	33.25%		33.25%
6	Total Effective Tax Rate	38.24%		38.24%
7	Total Effective Tax Rate Adjusted for Uncollectibles	38.17%		38.17%
8	Change in Net Operating Income	61.64%		61.64%
9	Gross Revenue Conversion Factor	1.6223	0.0000	1.6223

Notes and Sources

Column B: TEP filing, Schedule C-3 and UDR 1.068

[a] Average Retail Expense Ratio from Bad Debt Adjustment

[b] State Tax Rate (UDR 1.068)	Rate	Apportionment	Effective State Rate
Arizona Income Tax	4.90%	0.94136	4.61%
New Mexico Income Tax	6.20%	0.06380	0.40%
NM Offset			-0.02%
			4.99%

[c] Federal Effective Income Tax Rate (1-State Rate*Federal Rate)

1-State Income Tax Rate	95.01%		95.01%
Federal Income Tax Rate	35.0%		35.0%
Federal Effective Inocme Tax Rate	33.25%		33.25%

[d] Total Effective Tax Rate 38.24%

ARIZONA CORPORATION COMMISSION

Tucson Electric Power Company
Original Cost and RCND Adjusted Rate Base
ACC Jurisdictional
Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Original Cost			RCND		
		As Adjusted by TEP	Staff Adjustments	As Adjusted by Staff	As Adjusted by TEP	Staff Adjustments	As Adjusted by Staff
		(A)	(B)	(C)	(D)	(E)	(F)
1	Gross Utility Plant in Service	$ 3,997,101	$ (32,477)	$ 3,964,624	$ 7,834,269	$ (32,477)	$ 7,801,792
2	Less: Accumulated Depreciation	1,582,018	(10,939)	1,571,079	3,329,859	(10,939)	3,318,920
3	Total Net Utility Plant	2,415,083	(21,538)	2,393,545	4,504,410	(21,538)	4,482,872
4	Customer Advances for Construction	(11,046)		(11,046)	(15,465)		(15,465)
5	Customer Deposits	(19,400)		(19,400)	(19,400)		(19,400)
6	Deferred Credit-Contributed Plant and Retirement Obligations	(2,631)		(2,631)	(2,630)		(2,630)
7	Accumulated Deferred Income Taxes	(403,583)	(12,814)	(416,397)	(871,290)	(12,814)	(884,104)
8	Total Deductions	(436,660)	(12,814)	(449,474)	(908,785)	(12,814)	(921,599)
9	Allowance for Working Capital	101,143	7,942	109,085	101,143	7,942	109,085
10	Regulatory Assets	25,112		25,112	25,112		25,112
11	Regulatory Liabilities	-		-	-		-
12	Total Rate Base	$ 2,104,678	$ (26,410)	$ 2,078,268	$ 3,721,880	$ (26,410)	$ 3,695,470

Notes and Source
Columns A and D: TEP filing, Schedule B-1
Columns B and E: See Schedule E

	Fair Value Calculation (Per Company)		
13	Original Cost	$ 2,104,678	
14	RCND	$ 3,721,880	
15	Total	$ 5,826,558	
16	Average (Fair Value)	$ 2,913,279	Used in Schedule A
	Fair Value Calculation (Per Staff)		
17	Original Cost	$ 2,078,268	
18	RCND	$ 3,695,470	
19	Total	$ 5,773,738	
20	Average (Fair Value)	$ 2,886,869	Used in Schedule A

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Schedule C
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Tucson Electric Power Company
Adjusted Net Operating Income
ACC Jurisdictional

Test Year Ended June 30, 2015
(Thousands of Dollars)

Line	Description	As Adjusted by TEP (A)	Staff Adjustment (B)	As Adjusted by Staff (C)
	Operating Revenues			
1	Electric Retail Revenues	$ 909,303	$ -	$ 909,303
2	Sales for Resale	-	-	-
3	Other Operating Revenues	31,728	-	31,728
4	Total Operating Revnues	$ 941,031	$ -	$ 941,031
	Operating Expenses			
5	Fuel, Purchased Power, and Transmission	$ 303,925	$ -	$ 303,925
6	Other Operations and Maintenance Expense	334,931	(14,389)	320,542
7	Depreciation and Amortization	129,703	(10,919)	118,784
8	Taxes Other than Income Taxes	40,735	(712)	40,023
9	Income Taxes	33,356	10,434	43,790
10	Total Operating Expenses	$ 842,650	$ (15,587)	$ 827,063
11	Operating Income	$ 98,381	$ 15,587	$ 113,968

Notes and Sources
Column A: TEP filing, Schedule C-1
Column B: Staff Schedule E

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Tucson Electric Power Company
Cost of Capital
Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Reference	Amount	Percent	Cost Rate	Rate of Return
	(A)	(B)	(C)	(D)	(E)	(F)
	TEP'S PROPOSED					
	TEP Proposed Adjusted Fair Value Rate Base					
1	Original Cost Rate Base (OCRB)	Schedule B	2,104,678			
2	Reconstructed Cost New Depreciation (RCND)	Schedule B	3,721,880			
3	Fair Value Rate Base (FVRB)	Average Lines 1 & 2	2,913,279			
4	FVRB/OCRB Multiple	Line 3/Line 1	1.38419			
	TEP Proposed Adjusted Capital Structure for OCRB					WACC
5	Short-Term Debt		$ -	0.00%	0.00%	0.00%
6	Long-Term Bond Debt, Net	TEP Schedule D-1	1,441,656	49.97%	4.32%	2.16%
7	Common Stock Equity	TEP Schedule D-1	1,443,610	50.03%	10.35%	5.18%
8	Total Capital		$ 2,885,266	100.00%		7.34%
	TEP Proposed Fair Value Rate of Return					FVROR
9	Short-Term Debt		$ -	0.00%	0.00%	0.00%
10	Long-Term Bond Debt, Net	Line 1 x Line 6 (Debt %)	1,051,626	36.10%	4.32%	1.56%
11	Common Stock Equity	Line 1 x Line 7 (Equity %)	1,053,052	36.15%	10.35%	3.74%
12	FVRB Increment Above Original Cost	Line 3 - Line 1	808,601	27.76%	1.42%	0.39%
13	Total Capital		$ 2,913,279	100.00%		5.69%
	STAFF'S RECOMMENDATION					
	Staff Proposed Adjusted Fair Value Rate Base					
14	Original Cost Rate Base (OCRB)	Schedule B	2,078,268			
15	Reconstructed Cost New Depreciation (RCND)	Schedule B	3,695,470			
16	Fair Value Rate Base (FVRB)	Average Lines 14 and 15	2,886,869			
17	FVRB/OCRB Multiple	Line 16/Line 14	1.38907			
	Staff Proposed Adjusted Capital Structure for OCRB					WACC
18	Short-Term Debt		$ -	0.00%	0.00%	0.00%
19	Long-Term Bond Debt, Net	Staff Witness Dave Parcell	1,521,156	51.31%	4.14%	2.12%
20	Common Stock Equity	Staff Witness Dave Parcell	1,443,610	48.69%	9.35%	4.55%
21	Total Capital		$ 2,964,766	100.00%		6.68%
	Staff Proposed Fair Value Rate of Return					FVROR
22	Short-Term Debt		$ -	0.00%	0.00%	0.00%
23	Long-Term Bond Debt, Net	Line 14 x Line 19 (Debt %)	1,066,314	36.94%	4.14%	1.53%
24	Common Stock Equity	Line 14 x Line 20 (Equity %)	1,011,955	35.05%	9.35%	3.28%
25	FVRB Increment Above Original Cost	Line 14 - Line 18	808,601	28.01%	0.70%	0.20%
26	Total Capital		$ 2,886,869	100.00%		5.00%

Notes and Sources
Staff proposed capital structure and cost ratios - See Staff Witness David Parcell

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Schedule D.1
Page 1 of 1

Tucson Electric Power Company
Impact of Recommended **Cost of Captial** on Company's Proposed Revenue Requirements

(Thousands of Dollars)

Line	Description	TEP Fair Value	Staff Adjustment	Staff's Position
	(A)	(B)	(C)	(D)
1	**Adjusted Rate Base**	$ 2,913,279		$ 2,913,279
2	Weighted Average Cost of Capital	7.34%	-0.66%	6.68%
3	Fair Value Adjustment	-1.64%	-0.03%	-1.67%
4	Required Rate of Return	5.69%	-0.69%	5.00%
5	**Return Requirement**	$ 165,898	$ (20,159)	$ 145,740
6	Operating Revenues	$ 941,031		$ 941,031
7	Operating Expenses	$ 842,650		$ 842,650
8	**Net Operating Income**	$ 98,381		$ 98,381
9	**Income Deficiency**	$ 67,517		$ 47,360
10	Revenue Conversion Factor	1.6223		1.6223
11	**Revenue Deficiency**	$ 109,534	$ (32,704)	$ 76,830
12	Revenue Deficiency Percent Change		-29.86%	

ARIZONA CORPORATION COMMISSION

Tucson Electric Power Company
Summary of Staff's Rate Base and Operating Income Adjustments
ACC Jurisdictional
Test Year Ended June 30, 2015

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Schedule E
Page 1 of 3

(Thousands of Dollars)

Line	Description	Total Staff Adjustments	Page Subtotal	E-1 Post Test Year Plant	E-2 Post Test Year Plant Renewables	E-3 Sundt CHF (Retirement)	E-4 ADIT	E-5 Working Capital	E-6 Depreciation
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Rate Base								
1	Gross Utility Plant in Service	$ (32,477)	$ (32,297)	$ (15,857)	$ (16,340)	$ -			
2	Less: Accumulated Depreciation	(10,939)	(10,939)	(1,300)	(419)	(20)			(9,200)
3	Net Utility Plant in Service	(21,538)	(21,358)	(14,657)	(15,921)	20	-	-	9,200
4	Customer Advances for Construction	$ -	$ -						
5	Customer Deposits	-	-						
6	Deferred Credit - Contributed Plant and Retirement Obligations	-	-						
7	Accumulated Deferred Income Taxes	(12,814)	(12,814)				(12,814)		
8	Total Deductions	$ (12,814)	$ (12,814)	-	-	-	(12,814)	-	-
9	Allowance for Working Capital	$ 7,942	$ 7,942					7,942	
10	Regulatory Assets	-	-						
11	Regulatory Liabilities	-	-						
12	Total Rate Base	$ (26,410)	$ (26,229)	$ (14,657)	$ (15,921)	$ 20	$ (12,814)	$ 7,942	$ 9,200
	Operating Revenues								
13	Electric Retail Revenues	$ -	$ -						
14	Sales for Resale	-	-						
15	Other Operating Revenues	-	-						
16	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses								
17	Fuel, Purchased Power, and Transmission	$ -	$ -						
18	Other Operations and Maintenance Expense	(14,389)	-						
19	Depreciation and Amortization	(10,919)	(10,919)	(1,300)	(419)				(9,200)
20	Taxes Other than Income Taxes	(712)	(424)	(224)	(201)				
21	Income Taxes	10,434	4,338	583	237				3,518
22	Total Operating Expenses	$ (15,587)	$ (7,005)	$ (941)	$ (383)	$ -	$ -	$ -	$ (5,682)
23	Operating Income	$ 15,587	$ 7,005	$ 941	$ 383	$ -	$ -	$ -	$ 5,682

Notes and Sources

ARIZONA CORPORATION COMMISSION

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Schedule E
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Tucson Electric Power Company
Summary of Staff's Rate Base and Operating Income Adjustments
ACC Jurisdictional
Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Page Subtotal	E-7 Overhaul & Outage	E-8 Payroll and Payroll Taxes	E-9 Long Term Incentive Comp	E-10 Short Term Incentive Comp	E-11 Employee Benefits	E-12 SERP	E-13 D&O Insuance
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Rate Base								
1	Gross Utility Plant in Service	$ (180)			$ (180)				
2	Less: Accumulated Depreciation	-							
3	Net Utility Plant in Service	(180)	-	-	(180)	-	-	-	-
4	Customer Advances for Construction	$ -							
5	Customer Deposits	-							
6	Deferred Credit - Contributed Plant and Retirement Obligations	-							
7	Accumulated Deferred Income Taxes	-							
8	Total Deductions	$ -	-	-	-	-	-	-	-
9	Allowance for Working Capital	$ -							
10	Regulatory Assets	-							
11	Regulatory Liabilities	-							
12	Total Rate Base	$ (180)	$ -	$ -	$ (180)	$ -	$ -	$ -	$ -
	Operating Revenues								
13	Electric Retail Revenues	$ -							
14	Sales for Resale	-							
15	Other Operating Revenues	-							
16	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses								
17	Fuel, Purchased Power, and Transmission	$ -							
18	Other Operations and Maintenance Expense	(9,429)	(4,131)	(1,144)	(881)	(3,294)	520	(474)	(25)
19	Depreciation and Amortization	-							
20	Taxes Other than Income Taxes	(288)		(75)		(213)			
21	Income Taxes	3,716	1,580	466	337	1,341	(199)	181	10
22	Total Operating Expenses	$ (6,001)	$ (2,551)	$ (753)	$ (544)	$ (2,166)	$ 321	$ (293)	$ (15)
23	Operating Income	$ 6,001	$ 2,551	$ 753	$ 544	$ 2,166	$ (321)	$ 293	$ 15

Notes and Sources

ARIZONA CORPORATION COMMISSION

Tucson Electric Power Company
Summary of Staff's Rate Base and Operating Income Adjustments
ACC Jurisdictional
Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Page Subtotal	E-14 Outside Legal	E-15 Rate Case	E-16 Credit Card Processing Fees	E-17 Interest Synchronization			
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Rate Base								
1	Gross Utility Plant in Service	$ -							
2	Less: Accumulated Depreciation	-							
3	Net Utility Plant in Service	-	-	-	-	-	-	-	-
4	Customer Advances for Construction	$ -							
5	Customer Deposits	-							
6	Deferred Credit - Contributed Plant and Retirement Obligations	-							
7	Accumulated Deferred Income Taxes	-							
8	Total Deductions	$ -	-	-	-	-	-	-	-
9	Allowance for Working Capital	$ -							
10	Regulatory Assets	-							
11	Regulatory Liabilities	-							
12	Total Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Revenues								
13	Electric Retail Revenues	$ -							
14	Sales for Resale	-							
15	Other Operating Revenues	-							
16	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses								
17	Fuel, Purchased Power, and Transmission	$ -							
18	Other Operations and Maintenance Expense	(4,960)	(1,340)	(144)	(3,476)				
19	Depreciation and Amortization	-							
20	Taxes Other than Income Taxes	-							
21	Income Taxes	2,380	513	55	1,329	483			
22	Total Operating Expenses	$ (2,580)	$ (828)	$ (89)	$ (2,146)	$ 483	$ -	$ -	$ -
23	Operating Income	$ 2,580	$ 828	$ 89	$ 2,146	$ (483)	$ -	$ -	$ -

Notes and Sources

ARIZONA CORPORATION COMMISSION

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Schedule E-1
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Tucson Electric Power Company
Post Test Year Plant In Service After 12/31/15

Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
	RATE BASE			
1	Plant in Service	$ 55,717	$ (15,957)	$ 39,760
2	Accumulated Depreciation	$ 3,935	$ (1,300)	$ 2,635
3	Impact to Rate Base	$ 51,782	$ (14,657)	$ 37,125
	OPERATING INCOME			
4	Property Taxes			
5	General			
6	NBV		$ (1,762)	
7	Assessment Ratio		0.180	
8	Taxable Value		$ (317)	
9	Property Tax Rate		14.9788%	
10	Property Taxes		$ (48)	
11	Generation			
12	NBV		$ (11,984)	
13	Assessment Ratio		0.180	
14	Taxable Value		$ (2,157)	
15	Property Tax Rate		7.900011%	
16	Property Taxes		$ (161)	
17	Distribution			
18	NBV		$ (912)	
19	Assessment Ratio		0.180	
20	Taxable Value		$ (164)	
21	Property Tax Rate		15.2376%	
22	Property Taxes		$ (25)	
23	Total Property Taxes		$ (224)	$ (224)
24	Depreciation Expense		$ (1,300)	$ (1,300)
25	Total Property Taxes and Depreciation Expense	$ -	$ (1,523)	$ (1,523)
26	Total Effective Tax Rate	38.24%		38.24%
27	Total Income Tax	-	$ 583	583
28	Total Expense	$ -	$ (941)	$ (941)
29	Impact to Operating Income	$ -	$ 941	$ 941

Notes and Sources

Line 1 and 2, Column A TEP Schedule B-2, Page 4
Assessed Value and Property Tax Rate - UDR 1.001 Income - Property Tax Expense
Column B - see worksheet

ARIZONA CORPORATION COMMISSION

Tucson Electric Power Company
Post Test Year Plant In Service After 12/31/15

Test Year Ended June 30, 2015

Line	Description	Expected In Service Date	Total Company Post Test Year $	Total Depreciation	ACC Jurisdiction Ratio	ACC Post Test Year Amount	ACC Depreciation	NBV
		(A)	(B)	(C)	(D)	(E)	(F)	
	General							
1	303 Project # D141AFR 2014 Acct Financial Reporting	May-16	2,365,016	450,479	92.03%	$ 2,176,525	$ 414,576	$ 1,761,949
2	303 Project # D141OSP Oracle Services Procurement	May-16	380,252	380,252	92.03%	$ 349,945	$ 349,945	$ -
	Total General							$ 1,761,949
	Generation							
3	311 Project # D13AC90 Sundt Cooling Tower Blowdown	Dec-16	158,920	16,758	89.78%	$ 142,679	$ 15,045	$ 127,633
4	312 Project # D05AD32 San Juan Various Enviro Projs	Jan-16	220,886	7,786	89.78%	$ 198,311	$ 6,990	$ 191,321
5	312 Project # D12AC77 Sundt Condensate tank Piping	Dec-16	277,508	28,930	89.78%	$ 249,147	$ 25,974	$ 223,173
6	312 Project # D13SE01 SGS U1 Mercury	Mar-16	498,459	8,673	89.78%	$ 447,517	$ 7,787	$ 439,730
7	312 Project # D13SK02 SGS U2 Mercury	May-16	1,075,679	21,729	89.78%	$ 965,745	$ 19,508	$ 946,237
8	312 Project # D14AD79 Selective Non-Catalytic Reduc	April-16	$ 9,774,013	257,057	89.78%	$ 8,775,108	$ 230,785	$ 8,544,323
9	315 Project # D02AB96 Irv #3 Step Transformer Replmt	Jun-16	1,660,946	204,462	89.78%	$ 1,491,197	$ 183,566	$ 1,307,631
10	315 Project # D08AB07 Sundt U3 MCC Replacement	Jun-16	258,865	31,938	89.78%	$ 232,409	$ 28,674	$ 203,735
	Total Generation							$ 11,983,783
	Distribution							
11	362 Project # D09EO02 Wilmot T2 Replacement	See Note A	130,583	2,350	100.00%	$ 130,583	$ 2,350	$ 128,232
12	362 Project # D11DD93 NE T2A Swtchgr Replc	Jan-16	131,864	2,374	100.00%	$ 131,864	$ 2,374	$ 129,491
13	362 Project # D14NM15 Volt-Var Pilot Ph1 & 2	Jul-16	553,547	9,964	100.00%	$ 553,547	$ 9,964	$ 543,583
14	367 Project # D13LE28 RV- Tangerine West 3rd Fdr Tie	See Note A	112,774	2,413	100.00%	$ 112,774	$ 2,413	$ 110,360
	Total Distribution							$ 911,667
15	Total		$ 17,599,312	$ 1,425,165		$ 15,957,351	$ 1,299,953	$ 14,657,398

Note A: Per Company, these projects will be monitored to ensure they are achieving what is expected, and unitized prior to new rates going into effect

Notes and Sources

Column A, and B STF 16.3, Attachment STF 16.3 Projects
Column C UDR 1.001 Rate Base - Post Test Year Plant
Column D UDR 1.001 2015 TEP Rev Req Model, Tab Rate Base-Original Cost
Column E = Column B x Column D
Column F = Column C x Column D

ARIZONA CORPORATION COMMISSION

Tucson Electric Power Company
Post Test Year Plant In Service After 12/31/15 Work Paper

Source: UDR 1.001 Rate Base Post Test Year Plant

TEP SPC01, SPC02, SPC1X
CWIP Reconciliation (16450)
JUNE 2015 CWIP Balances

CWIP Hierarchy	FERC	Project Number	Description	Post Test Year	Cost Recovery Rates	NNS Rates	Annual Deprn		Total Company Net Book Value: Generation	Distribution	General
General Plant Software	303	D14IAFR	2014 Acct Financial Reporting	2,365,016.43	REMI		450,479.32	450,479.32			1,914,537.11
General Plant Software	303	D14IOSP	Oracle Services Procurement	380,251.50	REMI		380,251.50	380,251.50			-
Tucson Power Production	311	D13AC90	Sundt Cooling Tower Blowdown	39,730.12	0.0995	0.0533	6,086.65	6,086.65	33,643.46		
Tucson Power Production	311	D13AC90	Sundt Cooling Tower Blowdown	39,730.12	0.084	0.0533	5,454.95	5,454.95	34,275.17		
Tucson Power Production	311	D13AC90	Sundt Cooling Tower Blowdown	39,730.12	0.064	0.049	4,489.50	4,489.50	35,240.62		
Tucson Power Production	311	D13AC90	Sundt Cooling Tower Blowdown	39,730.12	0.0147	0.0036	727.06	727.06	39,003.06		
Reliables	312	D05AD32	San Juan Various Enviro Proj	110,443.02	0.0378	0.0025	4,428.77	4,428.77	106,014.25		
Reliables	312	D06AD32	San Juan Various Enviro Proj	110,443.02	0.0278	0.0026	3,357.47	3,357.47	107,085.55		
Reliables	312	D14AD79	Selective Non-Catalytic Reduc	9,774,012.66	0.0258	0.0025	257,056.63	257,056.63	9,516,956.03		
Springerville and Photovoltaic	312	D13SK02	SGS U2 Mercury	1,075,679.17	0.0188	0.0014	21,728.72	21,728.72	1,053,950.45		
Springerville and Photovoltaic	312	D13SE01	SGS U1 Mercury	498,459.36	0.0174	0	8,673.19	8,673.19	489,786.17		
Tucson Power Production	312	D12AC77	Sundt Condensate tank Piping	69,377.02	0.104	0.0502	10,697.94	10,697.94	58,679.08		
Tucson Power Production	312	D12AC77	Sundt Condensate tank Piping	69,377.02	0.0825	0.0537	9,449.15	9,449.15	59,927.87		
Tucson Power Production	312	D12AC77	Sundt Condensate tank Piping	69,377.02	0.0817	0.0487	7,520.47	7,520.47	61,856.55		
Tucson Power Production	312	D12AC77	Sundt Condensate tank Piping	69,377.02	0.0147	0.0035	1,262.66	1,262.66	68,114.36		
Tucson Power Production	315	D02AB88	Irv #3 Step Transformer Replmt	1,660,945.92	0.0715	0.0516	204,462.44	204,462.44	1,456,483.48		
Tucson Power Production	315	D05AB07	Sundt U3 MCC Replacement	258,864.69	0.0715	0.0516	31,866.24	31,866.24	226,998.45		
Tucson Power Production	315	D05AB10	Sundt U2 MCC Replacement	435.82	0.1007	0.0835	71.56	71.56	364.26		
Other Distribution	362	D14NM16	Volt-Var Pilot Ph1 & 2	553,547.06	0.0153	0.0027	9,963.86	9,963.86		543,583.21	
Other Distribution	362	D08EC02	Wilmot T2 Replacement	130,582.93	0.0153	0.0027	2,350.49	2,350.49		128,232.44	
Other Distribution	362	D11DD93	NE T2A Switchgr Replc	131,864.22	0.0153	0.0027	2,373.56	2,373.56		129,490.66	
Other Distribution	367	D13LE28	RV-Tangerine West 3rd Fdr Tie	112,773.68	0.0187	0.0027	2,413.36	2,413.36		110,360.32	
	Grand Total			61,407,076.25			1,425,165.38		13,348,378.81	911,666.64	1,914,537.11
			Plant Not In Service As of 12/31/15	17,599,747.94			1,425,165.38	16,174,582.56			16,174,582.56

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Tucson Electric Power Company
Post Test Year Plant In Service-Renewables In Service After 12/31/15

Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
	RATE BASE			
1	Plant in Service	$ 21,324	$ (16,340)	$ 4,984
2	Accumulated Depreciation	$ 530	$ (419)	$ 111
3	**Impact to Rate Base**	$ 20,794	$ (15,921)	$ 4,873
	OPERATING INCOME			
4	Property Taxes			
5	NBV	$ 20,794		$ 4,873
6	Assessment Ratio	0.180		0.180
7	Taxable Value	$ 3,743		$ 877
8	Property Tax Rate	7.000011%		7.000011%
9	Property Taxes	$ 262	$ (201)	$ 61
10	Depreciation Expense	$ 530	$ (419)	$ 111
11	Total Propoerty Taxes and Depreciation Expense	$ 792		$ 172
12	Total Effective Tax Rate	38.24%		38.24%
13	Total Income Tax	(303)	$ 237	(66)
14	Total Expense	$ 489	$ (383)	$ 106
15	**Impact to Operating Income**	$ (489)	$ 383	$ (106)

Notes and Sources

Line 1 and 2, Column A TEP Schedule B-2, Page 4
Lines 6 and 8 - UDR 1.001 Income-Property Tax Expense
Column B - see worksheet below

ARIZONA CORPORATION COMMISSION

Tucson Electric Power Company
Post Test Year Plant In Service-Renewables In Service After 12/31/15

Test Year Ended June 30, 2015

Line	Description	Expected In Service Date	Total Company Post Test Year $	Total Depreciation	ACC Jurisdiction Ratio	ACC Post Test Year Amount	ACC Depreciation
		(A)	(B)	(C)	(D)	(E)	(F)
1	344 Project No. D14PD43 Brt Buildout Plan Ft Huachuca Phase II	6/15/16	$ 8,200,000	210,330	89.78%	$ 7,361,960	$ 188,834
2	344 Project No. NA TEP Community Solar-Prima Cnty	9/20/16	10,000,000	256,500	89.78%	$ 8,978,000	$ 230,286
3	Total		$ 18,200,000	$ 466,830		$ 16,339,960	$ 419,120

Notes and Sources

Column A, B, and C UDR 1.001 Rate Base Post Test Year Renewables
Column D UDR 1.001 2015 TEP Rev Req Model, Tab Rate Base-Original Cost
Column E = Column B x Column D
Column F = Column C x Column D

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Tucson Electric Power Company
Sundt Coal Handling Facilities (Retirement) - ACC Jurisdictional Allocation

Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Gross Utility Plant in Service	$ (66,550)	$ -	$ (66,550)
2	Less: Accumulated Depreciation	$ (66,530)	$ (20)	$ (66,550)
3	Net Utility Plant in Service	$ (20)	$ 20	$ -
4	**Impact to Rate Base**	**$ (20)**	**$ 20**	**$ -**

Notes and Sources
Corrects wrong ACC Jurisdictional Allocation identified by Company
RUCO 6.4 - Identifying wrong ACC Jurisdictional allocation
Column A - UDR 1.001 - Rate Base-Sundt Coal Handling Facilities
Column C - UDR 1.001 - Rate Base-Sundt Coal Handling Facilities-Revised

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Tucson Electric Power Company
ADIT-Bonus Depreciation

Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	ADIT	$ (58,309)	$ (12,814)	$ (71,123)
2	**Impact to Rate Base**	**$ (58,309)**	**$ (12,814)**	**$ (71,123)**

Notes and Sources
Column A - UDR 1.001 Rate Base - Accumlated Deferred Income Taxes
Column C - AECC 1.3 Bonus - Rate Base - Accumulated Deferred Income Taxes

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Tucson Electric Power Company
Working Capital

Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Cash Working Capital	$ (10,529)	$ 2,825	$ (7,704)
2	Fuel Inventory	(4,655)		(4,655)
3	Materials and Supplies	(9,787)	(5,138)	(4,649)
4	Prepaids	(2,354)	(21)	(2,375)
5	**Impact to Rate Base**	$ (27,325)	$ 7,942	$ (19,383)

Notes and Sources

Line 1 - See CWC Workpaper
Line 3 - Adjustment to M&S to remove Sundt and San Juan M&S to be recovered through a regulaory asset
See TEP response to STF 7.21 and UDR 1.001 Rate Base-Working Capital Revised

As filed	9,787,349
Corrected	4,648,854
Difference	(5,138,495)

Line 4 - Adjutment to remove 50% of prepaid D&O Insurance - See D&O Adjustment

ARIZONA CORPORATION COMMISSION

Tucson Electric Power Company
Cash Working Capital Workpaper

Test Year Ended June 30, 2015

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Line	Description	TEP Proposed: Pro Forma Test Year Amount	Revenue Lag Days	Expense Lag Days	Net Lag Days (C - D)	Lead/Lag Factor (E/365)	Cash Working Capital (F x B)	Staff Recommendation: Adjustments	Cash Working Capital	
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	
	Operating Expenses									
	Non-Cash Expenses									
1	Bad Debts Expense	$ 1,723,975								
2	Depreciation	156,891,230						(10,919,369)		
3	Amortization	2,070,108								
4	Deferred Income Taxes	40,476,449								
5	Other Operating Expenses									
6	Salaries and Wages	71,355,823	38.62	10.46	28.16	0.0772	$ 5,508,654	(1,143,610)	(88,287)	
7	Incentive Pay	6,606,720	38.62	259.50	(220.88)	(0.6052)	$ (5,206,787)	(4,174,976)	2,526,695	
8	Fuel Expense	301,256,312	38.62	28.50	10.12	0.0277	$ 8,344,800		-	
9	Lease Expense	15,768,836	38.62	94.33	(55.71)	(0.1526)	$ (2,406,324)		-	
10	Remote Generating Plant O&M	47,732,871	38.62	(6.90)	45.52	0.1247	$ 5,952,289	(4,130,980)	(515,133)	
11	Office Supplies and Expenses	11,750,832	38.62	12.46	26.16	0.0717	$ 842,535		-	
12	Outside Services	12,768,854	38.62	44.51	(5.89)	(0.0161)	$ (205,578)	(1,484,483)	23,900	
13	Property Insurance	2,517,465	38.62	0.00	38.62	0.1058	$ 266,348	(25,000)	(2,645)	
14	Injuries and Damages	1,677,861	38.62	(13.27)	51.89	0.1422	$ 238,592		-	
15	Pension and Benefits	21,130,826	38.62	13.03	25.59	0.0701	$ 1,481,271	45,618	3,196	
16	Miscellaneous General Expenses	4,700,936	38.62	(2.00)	40.62	0.1113	$ 523,214		-	
17	Rents	819,229	38.62	(40.51)	79.13	0.2168	$ 177,609		-	
18	Property Taxes	46,931,391	38.62	213.43	(174.81)	(0.4789)	$ (22,475,443)	(424,109.08)	203,106	
19	Payroll Taxes	10,391,284	38.62	15.73	22.89	0.0627	$ 651,534	(1,926,957)	(120,820)	See Notes
20	Current Income Taxes	-	38.62	0.00	38.62	0.1058	$ -	10,433,917	1,103,908	
21	Other Taxes	78,937	38.62	91.38	(52.76)	(0.1445)	$ (11,406)		-	
22	Interest on Customer Deposits	31,250	38.62	182.50	(143.88)	(0.3942)	$ (12,319)		-	
23	Other Operations and Maintenance	76,989,263	38.62	11.99	26.63	0.0730	$ 5,620,216	(3,475,500)	(253,712)	
24	Total Operating Expenses	835,670,250						$ (17,225,448)		
								(1,638,792)		
25	Other Cash Working Capital Elements:							(15,586,656)		
26	Interest On Long-Term Debt	57,960,902	38.62	88.20	(47.58)	(0.1304)	(7,558,102)	(15,586,656)		
27	Revenue Taxes and Assessments	94,388,041	38.62	48.16	(9.54)	(0.0261)	(2,463,528)	-		
28	Total Cash Working Capital					Total Company	$ (10,734,427)		$2,880,211	
29						ACC Jurisdiction Ratio	98.08%		98.08%	
30						ACC Jurisdiction	(10,528,676)		$2,825,005	
		w/o Int Synch	w/ Int Synch	Int Synch						
31	Current Income Taxes	9,950,917	10,433,917	483,000						

Notes and Sources

Lead/Lag Study from TEP Schedule B-5, page 3 of 3
Line 19 - Payroll Tax Correction - See TEP response to STF 14.01

		Payroll Adj	
As Filed	10,391,284		
Corrected	8,752,492		
Difference	(1,638,792)	(288,166)	(1,926,957)

Line 29 - ACC Jurisdiction Ratio - 2015 TEP Rev Req Model, Tab Rate Base, Cell AP231

ARIZONA CORPORATION COMMISSION

Tucson Electric Power Company
Depreciation Expense

Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Total Company Company Adjusted (A)	Total Company Adjustment (B)	Total Company Staff Adjusted (C)	ACC Ratio (D)	ACC Jurisdictional Company Adjusted (E)	ACC Jurisdictional Adjustment (F)	ACC Jurisdictional Staff Adjusted (G)
	OPERATING INCOME							
1	Intangible Plant	$ 16,017	$ -	$ 16,017	82.90%	$ 13,278	$ -	$ 13,278
2	Steam Production Plant	66,856	(4,859)	61,996	89.78%	60,023	(4,362)	55,660
3	Other Production Plant	13,987	(598)	13,388	89.78%	12,557	(537)	12,020
4	Transmission Plant	13,159	-	13,159	-	-	-	-
5	Distribution Plant	29,159	(4,301)	24,858	100%	29,159	(4,301)	24,858
6	General Plant	17,714	-	17,714	82.90%	14,685	-	14,685
7	Depreciation Expense	$ 156,891	$ (9,758)	$ 147,133		$ 129,702	$ (9,200)	$ 120,502
8	Total Effective Tax Rate					38.24%		38.24%
9	Total Income Tax					(49,601)	3,518	(46,083)
10	Total Expense					$ 80,101		$ 74,419
11	**Impact to Operating Income**					$ (80,101)	$ 5,682	$ (74,419)
	RATE BASE							
12	Accumulated Depreciation					$ 129,702	$ (9,200)	$ 120,502
13	**Impact to Rate Base**					$ 129,702	$ (9,200)	$ 120,502

Notes and Sources
Column A - UDR 1.00a 2015 TEP Rev Req Model, Tab, Rev-Exp
Column B - Staff Testimony of Roxie McCullar

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Tucson Electric Power Company
Overhaul and Outage Normalization

Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Other O&M Expense - FERC 512 Maintenance	$ 5,176	$ (4,131)	$ 1,046
2	Total Effective Tax Rate	38.24%		38.24%
3	Total Income Tax	(1,980)	$ 1,580	(400)
4	Total Expense	$ 3,197	$ (2,551)	$ 646
5	**Impact to Operating Income**	**$ (3,197)**	**$ 2,551**	**$ (646)**

Notes and Sources
Column A - UDR 1.001 Income-Overhaul & Outage Normalization
Column C - See Testimony of Staff Witness Michael McGarry

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Tucson Electric Power Company
Payroll and Payroll Taxes

Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
	Payroll			
1	Total O&M Wages			
2	12 Months ended June 2014	$ 66,509		$ 66,509
3	12 Months ended June 2015	68,626		68,626
4	Average	67,567	-	67,567
5	2016 Rate Increase	2.00%		2.00%
6	2016 Wage Increase	1,351		1,351
		68,919		68,919
7	2017 Rate Increase	2.00%	-2.00%	0.00%
8	2017 Wage Increase	1,378		-
9	Total 2016 and 2017 Wage Increase	2,730		1,351
10	ACC 2016 and 2017 Wage Increase	$ 2,265	(1,144)	$ 1,121
	Payroll Taxes			
11	ACC 2016 and 2017 Wage Increase	$ 2,265		$ 1,121
12	Effective Payroll Tax Rate	6.60%		6.60%
13	Employer Payroll Tax	$ 149	(75)	$ 74
14	Total Payroll and Payroll Taxes	2,414		1,195
15	Total Effective Tax Rate	38.24%		38.24%
16	Total Income Tax	(923)	$ 466	(457)
17	Total Expense	$ 1,491	$ (753)	$ 738
18	**Impact to Operating Income**	**$ (1,491)**	**$ 753**	**$ (738)**

Notes and Sources
Column A, lines 1-9 UDR 1.001 Income - Payroll and Income-Payroll Taxes

ARIZONA CORPORATION COMMISSION

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Schedule E-6 WP
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Tucson Electric Power Company
Payroll and Payroll Taxes Workpaper

				Total Company			ACC	
% O&M Distribution by FERC			Distribute Payroll Adjustment					
Distribution	Account	Description	Company	Staff	ACC Ratio	Company	Staff
11.33%	0500	Steam Prod Oper-Supervision	309,352	153,145	89.78%	277,736	137,493
0.96%	0501	Fuel - Steam	26,739	13,237	100.00%	26,739	13,237
13.43%	0502	Steam Expenses	366,459	181,420	89.78%	329,016	162,879
4.46%	0505	Electric Expenses	121,744	60,269	89.78%	109,302	54,110
3.30%	0506	Steam Prod-Misc Expense	90,179	44,643	89.78%	80,963	40,081
0.07%	0546	Other Prod Oper-Supervision	1,945	963	89.78%	1,746	864
0.00%	0549	Misc Other Pw Gen Exp	5	2	89.78%	4	2
1.85%	0556	Sys Cntrol/Load Dispatch	50,486	24,993	0.00%	-	-
0.44%	0557	Prod Expense-Other	12,006	5,943	89.78%	10,779	5,336
2.05%	0560	Trans-Oper Supv & Engr	55,961	27,704	0.00%	-	-
0.00%	0566	Trans-Misc Oper Expense	-	-	0.00%	-	-
1.17%	5611	Load Dispatch-Reliability	32,047	15,865	0.00%	-	-
1.36%	5612	Load Dispatch-Monitor and Operation Transmiss	37,690	18,658	0.00%	-	-
1.00%	5613	Load Dispatch-Transmission Service and Schedu	27,225	13,478	0.00%	-	-
0.75%	0580	Dist-Oper Supv & Engr	20,456	10,127	100.00%	20,456	10,127
0.77%	0581	Dist-Load Dispatching	21,099	10,445	100.00%	21,099	10,445
0.30%	0582	Dist-Station Expenses	8,121	4,020	100.00%	8,121	4,020
0.69%	0583	Dist-Overhead Line Exp	18,937	9,375	100.00%	18,937	9,375
0.32%	0584	Dist-Underground Line Exp	8,782	4,347	100.00%	8,782	4,347
0.00%	0585	Dist-Light/Signal Exp	4	2	100.00%	4	2
1.17%	0586	Dist-Meter Expenses	32,033	15,858	100.00%	32,033	15,858
0.08%	0587	Dist-Customer Install Exp	2,131	1,055	100.00%	2,131	1,055
5.42%	0588	Dist-Misc Expense	147,935	73,235	100.00%	147,935	73,235
0.00%	0903	Cust Rec/Collection Exp	38	19	100.00%	38	19
0.00%	0902	Meter Reading Expense	21	10	100.00%	21	10
10.35%	0903	Cust Rec/Collection Exp	282,629	139,915	100.00%	282,629	139,915
0.10%	0908	Customer Assistance Exp	2,791	1,382	100.00%	2,791	1,382
0.01%	0909	Informational/Instrct Adv Exp	295	146	100.00%	295	146
0.00%	0920	A&G Salaries	-	-	83.91%	-	-
0.00%	0925	Injuries & Damages	(47)	(23)	83.91%	(40)	(20)
35.86%	0920	A&G Salaries	978,803	484,558	83.91%	821,314	406,591
0.11%	0923	Outside Services	2,919	1,445	83.91%	2,450	1,213
0.12%	0925	Injuries & Damages	3,222	1,595	83.91%	2,703	1,338
2.19%	0926	Pensions & Benefits	59,689	29,549	83.91%	50,085	24,794
0.29%	0930	General Advertising Exp	8,017	3,969	83.91%	6,727	3,330
0.00%	0935	Maint General Plant	-				
100.00%							
		Payroll Adjustment Amount:	2,729,720	1,351,346		2,264,794	1,121,185
						0.83	0.83

2,729,720 1,351,346

ARIZONA CORPORATION COMMISSION

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Schedule E-9
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Tucson Electric Power Company
Long Term Incentive Compensation

Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
	RATE BASE			
1	FERC 107 CWIP	$ 180	$ (180)	$ -
2	**Impact to Rate Base**	$ 180	$ (180)	$ -
	OPERATING INCOME			
3	FERC 920 A&G Salaries	$ 881	$ (881)	$ -
4	Total Effective Tax Rate	38.24%		38.24%
5	Total Income Tax	(337)	$ 337	-
6	Total Expense	$ 544	$ (544)	$ -
7	**Impact to Operating Income**	$ (544)	$ 544	$ -

Notes and Sources
Line 1 - Response to RUCO 5.2 h
Line 3 - Respone to UDR 1.001 Income-Long Term Incentive Compensation
Note: The Company corrected the amount to $1,000,112

ARIZONA CORPORATION COMMISSION

Docket No. E-01933A-15-0322
Schedule E-10
Page 1 of 1

Tucson Electric Power Company
Short Term Incentive Compensation

Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	ACC Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
3	Incentive Compensation	$ 6,466	$ (3,294)	$ 3,172
2	Payroll Taxes	$ 425	$ (213)	$ 213
3	Total Payroll Expense and Payroll Taxes	$ 6,891	$ (3,507)	$ 3,385
4	Total Effective Tax Rate	38.24%		38.24%
5	Total Income Tax	(2,635)	$ 1,341	(1,294)
6	Total Expense	$ 4,256	$ (2,166)	$ 2,090
7	**Impact to Operating Income**	**$ (4,256)**	**$ 2,166**	**$ (2,090)**

Notes and Sources
State and Federal Income Taxes - Schedule A.1
See Workpaper for Staff Adjustment

ARIZONA CORPORATION COMMISSION

Tucson Electric Power Company
Short Term Incentive Compensation Workpaper

Test Year Ended June 30, 2015

(Thousands of Dollars)

Docket No. E-01933A-15-0322
Schedule E-10 WP
Page 1 of 1

Line	Description	2013 (A)	1/2 of 2013 (B)	1/2 of 2013 Adjusted for Wage Increase (C)	2014 (D)	1/2 of 2014 (E)	1/2 of 2014 Adjusted for Wage Increase (F)	1/1/15-6/30/15 (G)	1/1/15-6/30/15 Adjusted for Wage Increase (H)	7/1/13-6/30/14 (I) (C+F)	7/1/14-6/30/15 (J) (F+H)	Average (K)	ACC Jurisdictional Allocation (L)	Total ACC (M) (K*L)
	As Filed by TEP													
1	Adjusted Incentive Compensation													
2	Wage Increase			2.00%			2.00%		2.00%					
3	# of Years to 2017			4			3		2					
4	0500	$ 145,454	$ 72,727	$ 78,545	$ 156,100	$ 77,550	$ 82,203	$ 62,164	$ 64,640	$ 160,748	$ 146,843	$ 153,796	88.78%	$ 136,578
5	0506	1,664,637	832,319	898,904	1,782,945	881,473	934,361	725,538	754,560	1,833,265	$ 1,781,093	1,807,179	88.78%	1,581,109
6	0614	586,971	293,486	316,965	684,841	342,421	362,966	282,108	293,382	679,930	656,348	668,144	88.78%	589,880
7	0596	1,093,292	546,646	590,378	1,257,204	628,602	666,318	357,300	371,592	1,256,696	1,037,910	1,147,303	0%	-
8	0570	108,710	54,355	58,703	104,201	52,100	55,226	26,160	27,206	113,930	82,433	98,181	0%	-
9	0580	8,513	4,256	4,597	-	-	-	-	-	4,597	-	2,298	100%	2,298
10	0586	377,815	188,908	204,020	410,962	205,481	217,810	240,180	249,787	421,830	467,597	444,714	100%	444,714
11	0598	95,386	47,696	51,514	105,772	52,886	56,059	60,018	62,419	107,573	118,478	113,025	100%	113,025
12	0903	373,806	186,903	201,747	248,987	124,984	132,483	118,608	123,352	334,230	255,835	295,032	100%	295,032
13	0920	3,282,814	1,641,407	1,772,720	3,979,023	1,989,511	2,108,882	1,784,406	1,855,784	3,881,602	3,964,666	3,923,134	83.91%	3,291,902
14	Total Incentive Compensation	$7,737,209	$3,868,805	$ 4,178,093	$8,710,014	$ 4,355,007	$ 4,616,307	$3,656,474	$3,802,733	$ 8,794,400	$ 8,418,040	8,606,720		$ 6,466,018
14	0408 Payroll Tax									$ 569,673	$ 562,727	$ 566,200	Blended	$ 425,372
15	% Payroll Tax to Total Incentive Comp									6.48%	6.68%	6.58%		6.58%
16	Total Incentive Comp and Payroll Tax									$ 9,364,074	$ 8,981,767	$ 9,172,920		$ 6,891,390

Line	Description	2013 (A)	1/2 of 2013 (B)	1/2 of 2013 Adjusted for Wage Increase (C)	2014 (D)	1/2 of 2014 (E)	1/2 of 2014 Adjusted for Wage Increase (F)	1/1/15-6/30/15 (G)	1/1/15-6/30/15 Adjusted for Wage Increase (H)	7/1/13-6/30/14 (I) (C+F)	7/1/14-6/30/15 (J) (F+H)	Average (K)	ACC Jurisdictional Allocation (L)	Total ACC (M) (K*L)
	Staff's Adjustment													
17	Adjusted Incentive Compensation													
18	Wage Increase			2.00%			2.00%		2.00%					
	# of Years to 2016-Removes Increase to 2017 as not K&M													
19				3			2		1					
20	0500	$ 145,454	$ 72,727	$ 77,091	$ 156,100	$ 77,550	$ 80,662	$ 62,164	$ 63,397	$ 157,743	$ 144,049	$ 150,896	89.78%	$ 135,474
21	0506	1,664,637	832,319	882,258	1,782,945	881,473	916,731	725,538	740,049	$ 1,798,989	1,656,780	1,727,885	89.78%	1,551,295
22	0614	586,971	293,486	311,095	684,841	342,421	356,117	282,108	287,750	667,212	643,858	655,540	89.78%	588,544
23	0596	1,093,292	546,646	579,445	1,257,204	628,602	653,746	357,300	364,446	1,233,190	1,018,192	1,125,691	0%	-
24	0570	108,710	54,355	57,616	104,201	52,100	54,184	26,160	26,683	111,801	80,868	96,334	0%	-
25	0580	8,513	4,256	4,512	-	-	-	-	-	4,512	-	2,256	100%	2,256
26	0586	377,815	188,908	200,242	410,962	205,481	213,700	240,180	244,984	413,942	458,684	436,313	100%	436,313
27	0598	95,386	47,696	50,566	105,772	52,886	55,001	60,018	61,218	105,567	116,220	110,893	100%	110,893
28	0903	373,806	186,903	198,011	248,987	124,984	129,983	118,608	120,980	327,994	250,963	289,479	100%	289,479
29	0920	3,282,814	1,641,407	1,739,891	3,979,023	1,989,511	2,069,092	1,784,406	1,820,096	3,808,983	3,888,186	3,849,086	83.91%	3,229,788
30														
31	Total Incentive Compensation	$7,737,209	$3,868,805	$ 4,100,721	$8,710,014	$ 4,355,007	$ 4,529,207	$3,656,474	$3,729,804	8,629,926	$ 8,258,811	$ 8,444,369		$ 6,344,019
32	0408 Payroll Tax									$ 569,673	$ 562,727	$ 566,200	Blended	$ 425,370
33	% Payroll Tax to Total Incentive Comp									6.60%	6.81%	6.71%		6.71%
34	Total Incentive Comp and Payroll Tax									$ 9,199,601	$ 8,821,538	$ 9,010,569		$ 6,769,388
35	50/50 Sharing													
36	Total Incentive Compensation													$ 3,172,009
37	Payroll Tax													$ 212,685
38	Total Incentive Comp and Payroll Tax													$ 3,384,695

Notes and Sources
TEP Proposed - UDR 1.001 Income -Short Term Incentive Compensation
ACC Jurisdictional Factors - UDR 1.001 2015 TEP Rev Req Model, Tab Rev-Exp, Column CN

ARIZONA CORPORATION COMMISSION

Docket No. E-01933A-15-0322
Schedule E-11
Page 1 of 1

Tucson Electric Power Company
Employee Benefits

Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
	926 Pension and Benefits			
1	Payroll Deductions-Benefits	$ -	$ (15,607)	$ (15,607)
2	401k	-	5,317	5,317
3	Medical Insurance	-	20,805	20,805
4	Dental Insurance	-	950	950
5	Life Insurance	-	749	749
6	Other Benefits	-	12,294	12,294
7	Long-Term Disability	-	541	541
8	Contractor Services	-	628	628
9	Total Benefits	$ -		$ 25,676
10	2% Increase 2016	$ -		$ 26,189
11	2% Increase 2017	$ -		$ 26,713
12	Adjustment from Test Year	$ -		$ 1,037
13	Payroll Charged to O&M	59.7%		59.7%
14	O&M Benefits	$ -		$ 619
15	ACC Jurisdictional Ratio	83.91%		83.91%
16	ACC Benefits Adjustment	$ -	$ 520	$ 520
17	Total Effective Tax Rate	38.24%		38.24%
18	Total Income Tax	-	$ (199)	(199)
19	Total Expense	$ -	$ 321	$ 321
20	**Impact to Operating Income**	$ -	$ (321)	$ (321)

Notes and Sources
Lines 1-16 - TEP response to STF 7.15
Line 16 - UDR 1.00a 2015 TEP Rev Req Model, Tab, Rev-Exp

ARIZONA CORPORATION COMMISSION

Docket No. E-01933A-15-0322
Schedule E-12
Page 1 of 1

Tucson Electric Power Company
Supplemental Executive Retirement Plan (SERP)

Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	926 Pension and Benefits - SERP	$ 565	$ (565)	$ -
2	ACC Jurisdictional Ratio	83.91%		83.91%
3	ACC Pension and Benefits - SERP	$ 474	$ (474)	$ -
4	Total Effective Tax Rate	38.24%		38.24%
5	Total Income Tax	(181)	$ 181	-
6	Total Expense	$ 293	$ (293)	$ -
7	**Impact to Operating Income**	**$ (293)**	**$ 293**	**$ -**

Notes and Sources

Line 1 - TEP respones to STF 7.15
Line 2 - 1.001 2015 TEP Rev Req Model, Tab Rev-Exp

ARIZONA CORPORATION COMMISSION

Docket No. E-01933A-15-0322
Schedule E-13
Page 1 of 1

Tucson Electric Power Company
Directors and Officers (D&O) Liability Insurance

Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
	RATE BASE			
1	D&O Included in Working Captial	$ 42	$ (21)	$ 21
2	**Carry forward to Working Capital Adjustment**	$ 42	$ (21)	$ 21
	OPERATING INCOME			
3	FERC 925 Officers & Directors Liability	$ 973		
4	Amount excluded by TEP in Fortis Merger Operating Income Adjustment	(923)		
5	D&O Liability Insurance in Test Year	50	$ (25)	25
6	Total Effective Tax Rate	38.24%		38.24%
7	Total Income Tax	(19)	$ 10	(10)
8	Total Expense	$ 31	$ (15)	$ 15
9	**Impact to Operating Income**	$ (31)	$ 15	$ (15)

Notes and Sources

Line 1 - TEP response to RUCO 7.06
Line 3 and 4 - TEP response to STF 7.18UDR 1.59
Total Effective Tax Rate - See Schedule A.1

ARIZONA CORPORATION COMMISSION

Docket No. E-01933A-15-0322
Schedule E-14
Page 1 of 1

Tucson Electric Power Company
Outside Legal Expenses

Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Legal Expenses	3,256	$ (1,340)	1,915
2	Total Effective Tax Rate	38.24%		38.24%
3	Total Income Tax	(1,245)	$ 513	(732)
4	Total Expense	$ 2,011	$ (828)	$ 1,183
5	**Impact to Operating Income**	**$ (2,011)**	**$ 828**	**$ (1,183)**

Notes and Sources
Line 1 - TEP response to AECC 10.1

ARIZONA CORPORATION COMMISSION

Docket No. E-01933A-15-0322
Schedule E-15
Page 1 of 1

Tucson Electric Power Company
Rate Case Expense

Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Rate Case Expense			
2	Outside Counsel	$ 600		
3	Depreciation Study	180		
4	Rate Design Study	225		
5	Outside Rate Case Consultant	85		
6	Cost of Equity Study	100		
7	Total Estimated Expense	$ 1,190	$ (290)	$ 900
8	Amortization period	3	1	4
9	Recovery per Year	$ 397		$ 225
10	ACC Jurisdiction	83.91%		83.91%
11	ACC Recovery per Year	$ 333		$ 189
12	Test Year Amortization	(225)		(225)
13	Rate Case Expense Amortization	$ 108	$ (144)	$ (36)
14	Total Effective Tax Rate	38.24%		38.24%
15	Total Income Tax	(41)	$ 55	14
16	Total Expense	$ 67	$ (89)	$ (22)
17	**Impact to Operating Income**	$ (67)	$ 89	$ 22

Notes and Sources

Column A - UDR 1.001 Income-Rate Case Expense

Company updated estimated rate case expenses as follows in STF 8.1

Rate Case Expense	
Outside Counsel	$ 600
Depreciation Study	200
Rate Design Study	225
Outside Rate Case Consultant	85
Cost of Equity Study	100
Total Estimated Expense	$ 1,210
Percent Increase over prior base rate case allowance of $900,000	34%

ARIZONA CORPORATION COMMISSION

Docket No. E-01933A-15-0322
Schedule E-16
Page 1 of 1

Tucson Electric Power Company
Credit Card Processing Fees

Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	903 Customer Records & Collection Expenses	$ 3,476	$ (3,476)	$ -
2	Total Effective Tax Rate	38.24%		38.24%
3	Total Income Tax	(1,329)	$ 1,329	-
4	Total Expense	$ 2,146	$ (2,146)	$ -
5	**Impact to Operating Income**	**$ (2,146)**	**$ 2,146**	**$ -**

Notes and Sources
Line 1 - UDR 1.001 Income - Credit Card Processing Fees

ARIZONA CORPORATION COMMISSION

Docket No. E-01933A-15-0322
Schedule E-17
Page 1 of 1

Tucson Electric Power Company
Interest Synchronization

Test Year Ended June 30, 2015

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Rate Base	$ 2,104,678	$ (26,410)	$ 2,078,268
2	Interest Component of Rate of Return	2.16%		2.12%
3	Interest Attributable to Rate Base	45,430	(1,285)	44,145
4	State Income Tax Rate	5.475%		5.475%
5	Effect on State income tax expense	$ (2,487)	$ 70	$ (2,417)
6	Federal Taxable	$ 42,943		$ 41,728
7	Federal Income Tax Rate	34%		34%
8	Effect on Federal income tax expense	$ (14,601)	$ 413	$ (14,188)
9	Total Income Tax		$ 483	
10	Total Expense	$ (17,088)	$ 483	$ (16,605)
11	**Impact to Operating Income**	$ 17,088	$ (483)	$ 16,605

Notes and Sources

Line 1 Original Cost Rate Base from Schedule B
Line 2 Interest Component of Rate of Return - OCRB Weighted Cost of Long Term Debt on Schedule D

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO UNIFORM DATA REQUESTS - 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
November 13, 2015

UDR 1.068

Tax Rate. Please provide the Company's effective tax rate used to calculate the revenue increase attributable net income deficiencies.

RESPONSE:

The combined effective income tax rate used by the Company for the revenue increase is 38.24%. Please see UDR 1.068 Tax Rates.xlsx for details. The Excel file is not identified by Bates number.

RESPONDENT:

W. Anne Jie

WITNESS:

Frank Marino

TUCSON ELECTRIC POWER COMPANY
RATE CASE - 6/30/2015 TEST YEAR
UDR 1.068
Tax Rates
/Users/tracymullinax/ownCloud/Projects/Arizona TEP/DMS/Responses/UDR/[UDR 1.068 Tax Rates.xlsx]Effective Tax Rates

	Statutory Rate in 2017	Apportionment (2014 Tax Return)
Federal	0.35	
AZ	0.049	0.94136
NM	0.062	0.063801

Rates with No Offset	
Federal	0.33254026
AZ	0.04612664
NM	0.00375833
Sum	**0.38242523**

Rates as they exist in Provision	
Federal	0.35000000
Federal Offset	-0.01745974
AZ	0.04612664
NM	0.00395566
NM Offset	-0.00019733
Sum	**0.38242523**

Rates as they should exist in Powertax	
Fed Statutory	0.35000000
Fed Offset - NM	-0.00137928
Fed Offset - AZ	-0.01608046
AZ Statutory	0.04612664
NM Statutory	0.00395566
NM Offset - NM	-0.00001487
NM Offset - AZ	-0.00018246
Sum	**0.38242523**

0.00000000

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SIXTEENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE DOCKET NO. E-01933A-15-0322 May 2, 2016

STF 16.3

Post Test Year Plant: For each project listed below, please provide the following:

a. The in-service status of each (provide date).

b. If the date is after 12/31/15, provide justification for inclusion in the post-test year ratebase adjustment.

Project ID	Amount
D14AD79	$ 9,774,012.56
D141AFR	$ 2,365,016.43
D02AB96	$ 1,660,945.92
D13SK02	$ 1,075,679.17
D14NM15	$ 553,547.06
D13SE01	$ 498,459.36
D141OSP	$ 380,251.50
D12AC77	$ 277,508.08
D08AB07	$ 258,864.69
D05AD32	$ 220,886.04
D13AC90	$ 158,920.48
D11DD93	$ 131,864.22
D09EO02	$ 130,582.93
D13LE28	$ 112,773.68

RESPONSE:

a. TEP is in the process of gathering the requested information and will provide it as soon as possible.

b. TEP is in the process of gathering the requested information and will provide it as soon as possible.

RESPONDENT:

David Lewis

WITNESS:

David Lewis

SUPPLEMENTAL RESPONSE: May 4, 2016

a. Please see the attached excel file "STF 16.3 Projects.xlsx" for in service status.

b. The Post-Test Year plant adjustment is limited to dollars invested as the end of the test year. These projects are expected to be in service prior to the new rate effective date and will provide customers the benefit during the life of these assets. This is consistent with the methodology approved in TEP's prior rate case.

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SIXTEENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 2, 2016

RESPONDENT:

Bernadette Porter

WITNESS:

Dallas Dukes

Tucson Electric Power
Post Test Year

Project Name	FERC	Project	Description	Amount	New Projected InSvc Date	
Remotes	312	D14AD79	Selective Non-Catalytic Reduc	9,774,012.56	April-16	
General Plant - Software	303	D141AFR	2014 Acct Financial Reporting	2,365,016.43	May-16	
Tucson Power Production	315	D02AB96	Irv #3 Step Transformer Replmt	1,660,945.92	JUN-16	
Springerville and Photovoltaic	312	D13SK02	SGS U2 Mercury	1,075,679.17	MAY-16	
Other Distribution	362	D14NM15	Volt-Var Pilot Ph1 & 2	553,547.06	JUL-16	
Springerville and Photovoltaic	312	D13SE01	SGS U1 Mercury	498,459.36	MAR-16	
General Plant - Software	303	D141OSP	Oracle Services Procurement	380,251.50	MAY-16	
Tucson Power Production	312	D12AC77	Sundt Condensate tank Piping	277,508.07	Dec-16	
Tucson Power Production	315	D08AB07	Sundt U3 MCC Replacement	258,864.69	JUN-16	
Remotes	312	D05AD32	San Juan Various Enviro Projs	220,886.04	JAN-16	
Tucson Power Production	311	D13AC90	Sundt Cooling Tower Blowdown	158,920.47	DEC-16	
Other Distribution	362	D11DD93	NE T2A Swtchgr Replc	131,864.22	JAN-16	
Other Distribution	362	D09EO02	Wilmot T2 Replacement	130,582.93	Status Change	1
Other Distribution	367	D13LE28	RV- Tangerine West 3rd Fdr Tie	112,773.68	Status Change	1

Notes:

(1.) These projects will be monitored to insure they are achieving what is expected, and unitized prior to new rates going into effect.

TUCSON ELECTRIC POWER COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2015

ADJUSTMENT NAME:	Property Tax Expense
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	October 22, 2015
PREPARED BY:	Eric Fowler
CHECKED BY:	
REVIEWED BY:	Jay Rademacher 10/22/15

		Total Company		ACC Jurisdictional	
FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT	DEBIT	CREDIT
	Generation	$10,821		$9,715	
	Transmission	$1,892,036		$0	
	Distribution	$3,123,911		$3,123,911	
	General/Intangible		$16,804		$13,930
	ENTRY TOTAL	$5,026,769	$16,804	$3,133,626	$13,930
	NET ENTRY	$5,009,965		$3,119,696	

Reason for Adjustment
To adjust property tax expense to reflect final adjusted balance of utility plant subject to property taxation, the property tax assessment rate scheduled to be in effect in 2016, the 2015 average AZ property tax rates, and the 2014 NM property tax rates.

Tucson Electric Power Company
Arizona Property Taxes
Test Year Ended 6/30/2015

		AZ Generation (excluding Gila River) 2014		Gila River 2014		Total Generation		Transmission 2014		Distribution 2014		General 2014		Total 2014
	Plant in Service													
1	Original Cost	A2.8A	1,824,452,859	A2.98*.75	156,146,863	1,980,599,722	A3A	746,367,407	A3B	1,392,752,252	A3C	294,066,646		4,413,786,027
2	Less: Environmental Property		-		-	-	A4B	(68,963,101)	A4A	(326,123,985)		-		(395,087,086)
3	Less: Fee Land*		-		-	-	A5C	(5,487,827)	A5A	(3,492,465)	A5B	(8,618,894)		(17,599,186)
4	Less: Land Rights of Way*		-		-	-	A5E	(34,141,913)	A5D	(8,105,548)		-		(42,247,461)
5	Less: Capitalized Stores	A6.2B	(785,811)		-	(785,811)					A6.2A	(1,014,121)		(1,799,932)
6	Less: Non-taxable Lic. Trans.		-		-	-		-		-	A8.1A	(40,688,284)		(40,688,284)
7														
8	Adjusted Original Cost		1,823,667,048		156,146,863	1,979,813,911		637,774,566		1,055,030,254		243,745,347		3,916,364,078
9	Full Cash Value Percentage	A7.2A	49.13610%	A7.2A	49.13610%	A7.2A 49.13610%	A7.2A	49.13610%	A7.2A	49.13610%	A7.2A	49.13610%		49.13610%
10	Full Cash Value		896,078,928		76,724,484	972,803,412		313,377,571		518,400,758		119,766,966		1,924,348,707
11	Assessment Ratio	A10A	0.180	A10A	0.180	A10A 0.180	A10A	0.180	A10A	0.180	A10A	0.180		0.180
12	Taxable Value		161,294,207		13,810,407 A	175,104,614		56,407,963		93,312,136		21,558,054		346,382,767
13	Property Tax Rate	A11.12A	6.9537%	A11.11A	7.5405% B	7.000011%	A11.13A	13.4575%	A11.14A	15.2376%	A11.15A	14.9788%		
14	Property Taxes		11,215,964		1,041,378	12,257,342		7,591,079		14,218,567		3,229,146		37,296,134
15														
16	**Land**													
17	Full Cash Value	A9.3A	2,902,602	A11B	53,016	2,955,618	A8.6A	10,702,857	A9.2A	2,884,251	A9.2B	2,966,465		19,508,991
18	Assessment Ratio	A10A	0.180	A10A	0.180	A10A 0.180	A10A	0.180	A10A	0.180	A10A	0.180		0.180
19	Taxable Value		522,468		9,543	532,011		1,926,478		519,165		533,964		3,511,618
20	Property Tax Rate	A11.12A	6.9537%	A11A	7.5405%		A11.13A	13.4575%	A11.14A	15.2376%	A11.15A	14.9788%		
21	Property Taxes		36,331		720	37,051		259,255		79,109		79,982		455,396
22														
23	**Environmental Plant**													
24	Original Cost		-		-	-	A4B	68,963,101	A4A	326,123,985				395,087,086
25	Full Cash Value Percentage	A7.2B	29.46868%	A7.2B	29.46868%	A7.2B 29.46868%	A7.2B	29.46868%	A7.2B	29.46868%	A7.2B	29.46868%		29.46868%
26	Full Cash Value		-		-	-		20,322,519		96,104,448		-		116,426,967
27	Assessment Ratio	A10A	0.180	A10A	0.180	A10A 0.180	A10A	0.180	A10A	0.180	A10A	0.180		0.180
28	Taxable Value		-		-	-		3,658,053		17,298,801		-		20,956,854
29	Property Tax Rate	A11.12A	6.9537%	A11A	7.5405%		A11.13A	13.4575%	A11.14A	15.2376%	A11.15A	14.9788%		
30	Property Taxes		-		-	-		492,281		2,635,929		-		3,128,210
31														
32	**Renewables**													
33	Original Cost		-		-	C1A 135,573,386		-		-		-		135,573,386
34	Full Cash Value Percentage	A8A	17.28890%	A8A	17.28890%	A8A 17.28890%	A8A	17.28890%	A8A	17.28890%	A8A	17.28890%		17.28890%
35	Full Cash Value		-		-	23,439,147		-		-		-		23,439,147
36	Assessment Ratio	A10A	0.180	A10A	0.180	A10A 0.180	A10A	0.180	A10A	0.180	A10A	0.180		0.180
37	Taxable Value		-		-	4,219,046		-		-		-		4,219,046
38	Property Tax Rate	A11.12A	6.9537%	A11A	7.5405%	C1C 7.000011%	A11.13A	13.4575%	A11.14A	15.2376%	A11.15A	14.9788%		
39	Property Taxes		-		-	295,334		-		-		-		295,334
40														
41														
42														
43														
44	**Plant in Service (ARIZONA)**													
45	Change in NBV (6/30/15 vs 12/31/2014)					H1 4B 2,529,765	D1.4B	26,483,367	D3.3B	27,730,204	D4.5B	8,397,969		65,141,305
46	Assessment Ratio					A10A 0.180	A10A	0.180	A10A	0.180	A10A	0.180		0.180
47	Taxable Value					455,358		4,767,006		4,991,437		1,511,634		11,725,435
48	Property Tax Rate					A1B 7.000011%	A11.13A	13.4575%	A11.14A	15.2376%	A11.15A	14.9788%		
49	Property Taxes					31,875		641,518		760,577		226,425		1,660,395
50														

Tucson Electric Power Company
Arizona Property Taxes
Test Year Ended 6/30/2015

			AZ Generation (excluding Gila River) 2014		Gila River 2014		Total Generation		Transmission 2014		Distribution 2014		General 2014		Total 2014
51															
52	**Plant in Service (NEW MEXICO)**														
53	Property Value (TY 2015)					F1.1C	282,095,025	F1.1T	39,923,306		-	F1.1A	2,451,230	324,469,561
54	Assessment Ratio					F1.3A	0.333	F1.3A	0.333	F1.3A	0.333	F1.3A	0.333	0.333
55	Taxable Value					F1.1D	94,031,675	F1.1F	13,307,769		-	F1.1B	817,077	108,156,520
56	Property Tax Rate					E1A	2.4713%		2.4713%		2.4713%		2.4713%	
57	Property Taxes						2,323,805		328,875		-		20,192	2,672,872
58														
59														
60	**Plant in Service (NEW MEXICO)**													
61	Change in NBV (6/30/15 vs 12/31/2014)					G1.1B	28,367,864	G2.1B	(641,644)		-	G3.1B	(212,281)	27,513,939
62	Assessment Ratio					F1.3A	0.333	F1.3A	0.333	F1.3A	0.333	F1.3A	0.333	0.333
63	Taxable Value						9,455,955		(213,881)		-		(70,760)	9,171,313
64	Property Tax Rate					E1A	2.4713%	E1A	2.4713%	E1A	2.4713%	E1A	2.4713%	
65	Property Taxes						233,685		(5,286)		-		(1,749)	226,651
66														
67														
68	**Adjustment to Remove Portion of SGS Coal Handling**													
69	Total SG3 CH FCV					I1.1A	40,593,224							40,593,224
70	Less: 17.05% related to TriState	I1.5A				Calc	(6,921,145)							(6,921,145)
71	Less: 17.05% related to SRP	I1.5B				Calc	(6,921,145)							(6,921,145)
72	Less: 16.64% related to other Unit 1 owners	I1.5C				Calc	(6,754,712)							(6,754,712)
73	Subtotal TEP						19,996,222							19,996,222
74	Less: Railroad 45.31% Allocable to PPFAC	H2.5Z				Calc	(9,060,288)							(9,060,288)
75	TEP Allocable to Base Rates						10,935,934							10,935,934
76														
77	Total Subtractions						(29,657,290)							(29,657,290)
78	Assessment Ratio					A10A	0.180							0.180
79	Taxable Value						(5,338,312)							(5,338,312)
80	Property Tax Rate					A1B	7.000011%							
81	Property Taxes						(373,682)							(373,682)
82														
83														
84	**Adjustment to Remove Sundt Coal Handling**													
85	Total Sundt 4 FCV					A2.3B	70,502,998							70,502,998
86	Less: 36.99% related to CH Facilities	I2.5A				Calc	(26,079,059)							(26,079,059)
87	TEP Amount Remaining						44,423,939							44,423,939
88														
89	Total Subtractions						(26,079,059)							(26,079,059)
90	Assessment Ratio					A10A	0.180							0.180
91	Taxable Value						(4,694,231)							(4,694,231)
92	Property Tax Rate					A1B	7.000011%							
93	Property Taxes						(328,597)							(328,597)
94														
95														
96	**Adjustment to Limit San Juan 2 to 20% or original cost per NMSA Sec 7-36-29(C)(3)**													
97	NBV of San Juan Unit 2					J1B	106,905,755							106,905,755
98	20% Original Cost Minimum Value					J1C	44,742,907							44,742,907
99	Reduction to San Juan 2						(62,162,848)							(62,162,848)
100	Assessment Ratio					F1.3A	0.333							0.333
101	Taxable Value						(20,720,949)							(20,720,949)
102	Property Tax Rate					E1A	2.4713%							
103	Property Taxes						(512,077)							(512,077)
104														

Tucson Electric Power Company
Arizona Property Taxes
Test Year Ended 6/30/2015

			AZ Generation (excluding Gila River) 2014		Gila River 2014		Total Generation		Transmission 2014		Distribution 2014		General 2014	Total 2014
105														
106	**Increase for Post Test Year Plant Adjustment - AZ**													
107	NBV per Pro-Forma Adjustment					R1B	12,619,830		-	R1C	8,882,431	R1D	3,847,784	25,350,045
108	Assessment Ratio					A10A	0.180	A10A	0.180	A10A	0.180	A10A	0.180	0.180
109	Taxable Value						2,271,569		-		1,598,838		692,601	4,563,008
110	Property Tax Rate					A1B	7.000011%	A11.13A	13.4575%	A11.14A	15.2376%	A11.15A	14.9788%	
111	Property Taxes						159,010		-		243,625		103,744	506,379
112														
113														
114	**Increase for Post Test Year Plant Adjustment - NM**													
115	NBV per Pro-Forma Adjustment					K1B	18,837,159		-		-		-	18,837,159
116	Assessment Ratio					F1.3A	0.333	F1.3A	0.333	F1.3A	0.333	F1.3A	0.333	0.333
117	Taxable Value						6,279,053		-		-		-	6,279,053
118	Property Tax Rate					E1A	2.4713%	E1A	2.4713%	E1A	2.4713%	E1A	2.4713%	
119	Property Taxes						155,174		-		-		-	155,174
120														
121														
122	**Increase for Post Test Year Plant Adjustment - AZ Renewables**													
123	NBV per Pro-Forma Adjustment (Less: 20% Tax Credit)					L1B	4,638,148		-		-	L1B	5,202	4,638,350
124	Assessment Ratio						0.180	F1.3A	0.180	F1.3A	0.180	F1.3A	0.180	0.180
125	Taxable Value						833,967		-		-		936	834,903
126	Property Tax Rate						7.000011%	A11.13A	13.4575%	A11.14A	15.2376%	A11.15A	14.9788%	
127	Property Taxes						58,378		-		-		140	58,518
128														
129														
130	**Increase for Delayed Plant Adjustment - AZ**													
131	NBV per Pro-Forma Adjustment					M1.4A	752,087		-	M1.4B	6,329,440	M1.4C	1,713,860	8,795,387
132	Assessment Ratio					A10A	0.180	A10A	0.180	A10A	0.180	A10A	0.180	0.180
133	Taxable Value						135,376		-		1,139,299		308,495	1,583,170
134	Property Tax Rate					A1B	7.000011%	A11.13A	13.4575%	A11.14A	15.2376%	A11.15A	14.9788%	
135	Property Taxes						9,476		-		173,602		46,209	229,288
136														
137	**Increase for Delayed Plant Adjustment - NM**													
138	NBV per Pro-Forma Adjustment													
139	Assessment Ratio					M2A	4,835,244		-		-		-	4,835,244
140	Taxable Value					E1A	0.333	E1A	0.333	E1A	0.333	E1A	0.333	0.333
141	Property Tax Rate						1,611,748		-		-		-	1,611,748
142	Property Taxes					F1.3A	2.4713%	F1.8A	2.4713%	F1.3A	2.4713%	F1.9A	2.4713%	
143							39,831		-		-		-	39,831
144														
145	**Navajo Nation Taxes**													
146	Four Corners PIT	N1.1A	836,550				836,550							836,550
147	Navajo Generating Station PIT	N1.2A	516,074				516,074							516,074
148	Navajo Lease - Additional Tax Payments	N1.3A-N1.2A	227,578				227,578							227,578
149	Total		1,580,202				1,580,202							1,580,202
150														
151	Remove SGS 3&4 Common Allocation					P1A	(158,636)							(158,636)
152														
153														
154	**Summary**													
155	Sub-Total Property Tax Expense					Calc	15,808,170	Calc	9,307,722	Calc	18,111,409	Calc	3,704,090	46,931,392
156														
157	Total Property Tax Expense						15,808,170		9,307,722		18,111,409		3,704,090	46,931,392
158														
159	Unadjusted (07/2014 through 06/2015)					B1A	16,640,756	B1B	7,415,686	B1C	14,987,498	B1D	3,720,894	42,764,834
160	Non Recurring Revenue & Expense Pro Forma					B4.1A	(475,725)							(475,725)
161	Springerville 3&4 Pro Forma					B3A	(367,682)							(367,682)
162	Unadjusted after Other Rate Case Pro Formas						15,797,349		7,415,686		14,987,498		3,720,894	41,921,427
163														
164	Adjustment						10,821		1,892,036		3,123,911		(16,804)	5,009,965

G:\TAXSVCS\Rate Cases\TEP\2015 (6-30-15 Test Year)\Property Tax Expense\Income - Property Tax.xls

TEP(0322)003205

Docket No. E-01933A-15-0322
Attachment DHM-5
Page 4 of 4

TUCSON ELECTRIC POWER COMPANY
RATE BASE STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2015

ADJUSTMETN NAME:	Post Test Year Plant - Renewables
ADJUSTMENT TO:	Rate Base
DATE SUBMITTED:	September 08, 2015
PREPARED BY:	Bernadette Porter
CHECKED BY:	Rigo Rameriz
REVIEWED BY:	David Lewis

		Total Company			ACC Jurisdictional	
FERC ACCT	**FERC ACCOUNT DESCRIPTION**	**DEBIT**	**CREDIT**		**DEBIT**	**CREDIT**
101	**Plant In - Service**					
312	Boiler plant equipment	$5,500,000		a	$4,938,053	
344	Generators	$18,224,916			$16,362,835	
397	Communication equipment	$26,695			$23,485	
1081	**Accumulated Depreciation**					
312	Boiler plant equipment		91,850	b		$82,465
344	Generators		467,328			$447,039
397	Communication equipment		685			$603
	ENTRY TOTAL	**$23,751,611**	**$559,863**		**$21,324,373**	**$530,107**
	NET ENTRY	**$23,191,748**			**$20,794,266**	

Reason for Adjustment

To adjust rate base to include used and useful renewable plant additions that have been, or are expected to be placed in service between July, 1, 2015 and December 31, 2016.

Tucson Electric Power
CWIP Balances PV
Test Year End of June 2015

Class	Project	Project & Description	Amount	In-Service Date	FERC	Capital Rate	NNS Rate	Period	Depreciation
Solar	D11PD37	Areva 5MW Solar Steam Gen	5,500,000.00	12/31/2015	312	0.03340		0	6	91,850.00
Solar	D14PD43	Brt Buildout Plan Ft Huachuca Phase II	8,200,000.00	6/15/2016	344	0.0513		0	6	210,330.00
Solar	NA	TEP Community Solar-Pima Cnty	10,000,000.00	9/20/2016	344	0.0513		0	6	256,500.00
Solar	D12PD38	Prairie Fire	1.25	12/28/2014	344	0.0513		0	6	0.03
Solar	CBOPD01	Residential Solar	24,914.44	6/17/2015	344	0.0400		0	6	498.29
Solar	D14PD45	SGSSS-Solar	10,303.73	12/15/2014	397	0.0513		0	6	264.29
Solar	D14RI02	Ft Huachuca - Solar	16,391.11	12/31/2014	397	0.0513		0	6	420.43
			23,751,610.53							559,863.04

TEP(0322)003606

Docket No. E-01933A-15-0322
Attachment DHM-6
Page 2 of 2

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
February 26, 2016

STF 3.6

Pro Forma Adjustment Post Test Year Plant – Renewables $20.794m.

Reference Company Witness dukes, Direct Testimony, page 44.

a. Please confirm that the projects included in this adjustment will not be recovered in the REST Tracker.

b. Were the following projects placed into service as expected and for the estimated amounts? If not, why not?

   i. Project D11PD37 – Areva 5MW Solar Steam Gen. - $5,500,000, expected in service date is 12/31/15.

   ii. Project CDQPD01 – Residential Solar - $24,914, expected in service date is 6/17/15.

   iii. Project D14PD45 – SGSSS-Solar - $10,303, expected in service date is 12/15/14.

   iv. Project D14R102 – Ft. Huachuca – Solar - $16,391, expected in service date is 12/31/14.

c. Project TEP Community Solar – Pima city was estimated to be $10,000,000 with an in-service date of 9/20/16. Please provide the detail as to how the estimated cost was determined.

d. Project Brt Buildout Plan Ft. Huachuca Phase II was estimated to be $8,000,000 with an in service date of 6/15/16. Please provide the detail as to how the estimated cost was determined.

e. Please confirm that none of the projects in this adjustment are included in either the Post Test Year Plant or Delayed Unitization adjustments.

RESPONSE:

a. Confirmed. Once these projects are recovered though base rates they will not be recovered through the REST Tracker

b. (i.) Yes.

   (ii) Yes.

   (iii) Yes.

   (iv) Yes.

c. Cost estimation on this renewable project was determined by taking 5 MW times $2 per watt. The $2 per watt reflects the costs related to land, procurement, and construction.

d. Cost estimation on this renewable project was determined by taking 5 MW times $2 per watt. The $2 per watt reflects the costs related to land, procurement, and construction. Less the $2 million savings on the intersection already built in Phase 1.

e. Confirmed.

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
February 26, 2016

RESPONDENT:

Bernadette Porter

WITNESS:

Dallas Dukes

Arizona Corporation Commission ("Commission")
Fortis Inc. ("Fortis")
Tucson Electric Power Company ("TEP" or the "Company")
UNS Energy Corporation ("UNS")

UniSource Energy Services ("UES")
UniSource Energy Development Company ("UED")
UNS Electric, Inc. ("UNS Electric")
UNS Gas, Inc. ("UNS Gas")

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 15, 2016

RUCO 6.4

Sundt Coal Handling Facilities – Please answer the following questions as they relate to the Sundt Coal Handling Facilities:

a. If the Company has removed the Sundt coal handling fees from rate base in its test year adjusted amount, then why was a pro-forma adjustment in the amount of $19,120 necessary? Please explain.

b. To clarify based on the Company's Rate Base – Sundt pro forma adjustment does the Company intend to create a regulatory asset for the remaining $16,406,677 of net book value?

c. To clarify does the Company intend to start recovery of the regulatory asset in this rate case or in the next rate case?

d. What is the amortization rate that the Company intends to apply to the regulatory asset?

e. Why is it appropriate to record the offset of the remaining unrecovered investment against the excess generation depreciation reserve?

RESPONSE: **April 14, 2016**

TEP is in the process of gathering this information and will provide it as soon as possible.

RESPONDENT:

Bernadette Porter

WITNESS:

Frank Marino

SUPPLEMENTAL RESPONSE: **April 15, 2016**

a. The wrong ACC Jursdictional allocation was applied. Please see Rate Base - Sundt Coal Handling Facilities-Revised.xlsx provided in the supplemental response to UDR 1.001 dated April 15, 2016.

b. Yes, as stated in Frank Marino's direct testimony, page 9, lines 16 – 20, "As these facilities are still being recovered in TEP's rates, the investment will be transferred to a regulatory asset account and amortized at the same rate it would otherwise have been depreciated as plant in service…."

c. TEP does not intend to recover these regulatory assets in the current or future rate cases.

d. See RUCO 6.4b response.

e. In accordance with the Settlement Agreement in TEP's 2012 rate case final Decision 73912 (dated June 27, 2013), page 29 lines 23 – 26 "In recognition of RUCO's concern about excess deprecation, TEP agrees that in any filing related to the early retirement of a production asset, TEP will propose that any then-existing excess deprecation reserve will

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 15, 2016

be applied to the unrecovered book value of the retiring assets and that TEP will propose in the next rate case that the remaining excess depreciation, if any will be made over 15 years".

RESPONDENT:

Bernadette Porter

WITNESS:

Frank Marino

TUCSON ELECTRIC POWER COMPANY

BALANCE SHEET PRO FORMA ADJUSTMENT

TEST YEAR ENDED June 30, 2015

ADJUSTMENT NAME:		Sundt Coal Handling Facilities
ADJUSTMENT TO:		Balance Sheet
DATE SUBMITTED:		September 21, 2015
PREPARED BY:		Chrissy Cuevas
CHECKED BY:		
REVIEWED BY:		Jay Rademacher

		Total Company		ACC Jurisdictional		Carry to Schedule B-3
FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT	DEBIT	CREDIT	
0101	Plant in Service					
311	Structures and improvements		$131,135		$117,737	-117,737.00
312	Boiler plant equipment		$82,222,143		$73,821,326	-73,821,326.00
315	Accessory electric equipment		$15,782		$14,170	-14,170.00
0114	Acquisition Adjustment					
311	Structures and improvements	$579,845		$520,585		520,585.00
312	Boiler plant equipment	$6,644,423		$5,965,592		5,965,592.00
314	Turbogenerator units	$323,842		$290,745		290,745.00
315	Accessory electric equipment	$864,268		$596,380		596,380.00
316	Misc. Power Plant equipment	$34,199		$30,704		30,704.00
						-66,549,227.00
0115	Amortization of Acquisition Adjustment					
311	Structures and improvements		$52,851		$47,450	-47,449.53
312	Boiler plant equipment		$605,611		$543,739	-543,738.56
314	Turbogenerator units		$29,517		$26,500	-26,500.36
315	Accessory electric equipment		$60,545		$54,357	-54,357.30
316	Misc. Power Plant equipment		$3,117		$2,798	-2,798.44
1081	Accumulated Provision - Depreciation					
311	Structures and improvements		$395,859		$356,413	-355,413.00
312	Boiler plant equipment	$76,183,331		$68,399,513		68,399,513.00
314	Turbogenerator units		$294,325		$264,253	-264,253.00
315	Accessory electric equipment		$587,941		$527,870	-527,870.00
316	Misc. Power Plant equipment		$31,082		$27,906	-27,906.00
						66,549,226.71
	ENTRY TOTAL	$84,429,908	$84,429,908	$75,803,519	$75,803,519	
	NET		$0		$0	

Reason for Adjustment

To adjust plant in service and accumulated depreciation for the early retirement of the Sundt Unit 4 Coal Handling.

Source:

UDR 1001 - Rate Base - Sundt Coal Handling Facilities-Revised

Tucson Electric Power Company
RATE BASE PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2015

ADJUSTMENT NAME:	Accumulated Deferred Income Taxes
ADJUSTMENT TO:	Rate Base
DATE SUBMITTED:	October 23, 2015
PREPARED BY:	Donye' Bonsu 10/23/15
CHECKED BY:	
REVIEWED BY:	Jay Rademacher 10/23/15

		Total Company		ACC Jurisdictional	
FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT	DEBIT	CREDIT
190	ADIT	-	175,121,198		$141,245,438
282	ADIT - Other Property	41,326,508	-	$33,332,234	
283	ADIT - Other	51,043,022	-	$49,604,518	
	ENTRY TOTAL	$92,369,530	$175,121,198	$82,936,752	$141,245,438
	NET ENTRY		$82,751,668		$58,308,686

Reason for Adjustment

To adjust rate base to reflect the pro forma test year ADIT.

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO AECC FIRST SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE DOCKET NO. E-01933A-15-0322 January 14, 2016

AECC 1.3

Bonus tax depreciation. Using TEP's direct case as a starting point, what is the impact on the TEP's revenue requirement resulting from the five year extension of bonus tax depreciation in H.R. 2029 (as signed into law by President Obama on December 18, 2015)? Please provide the adjustments necessary on both a Total Company and ACC Jurisdictional basis necessary to reflect the impact of this extension on TEP's requested revenue increase. Please provide the workpapers used to support this response in Excel format with formulas intact.

RESPONSE: January 4, 2016

TEP is in the process of evaluating the H.R. 2029 through its year end close process and will respond as soon as possible.

RESPONDENT:

Jason Rademacher

WITNESS:

Frank Marino

SUPPLEMENTAL RESPONSE: January 14, 2016

For an updated Accumulated Deferred Income Tax pro forma adjustment that includes the impacts of the extension of bonus depreciation, see AECC 1.3 Bonus - Rate Base - Accumulated Deferred Income Taxes.xlsm. This update would reduce the overall revenue requirement by approximately $1.5 million. The Excel file is not identified by Bates numbers.

RESPONDENT:

Jason Rademacher

WITNESS:

Frank Marino

Tucson Electric Power Company
RATE BASE PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2015

ADJUSTMENT NAME:	Accumulated Deferred Income Taxes
ADJUSTMENT TO:	Rate Base
DATE SUBMITTED:	January 13, 2016
PREPARED BY:	Donye' Bonsu
CHECKED BY:	
REVIEWED BY:	Jay Rademacher

		Total Company		ACC Jurisdictional	
FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT	DEBIT	CREDIT
190	ADIT	-	168,923,600		$136,246,714
282	ADIT - Other Property	19,241,437	-	$15,519,338	
283	ADIT - Other	51,043,022	-	$49,604,518	
	ENTRY TOTAL	**$70,284,459**	**$168,923,600**	**$65,123,856**	**$136,246,714**
	NET ENTRY		**$98,639,141**		**$71,122,858**

Reason for Adjustment

To adjust rate base to reflect the pro forma test year ADIT.

TUCSON ELECTRIC POWER COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2015

ADJUSTMENT NAME:	Working Capital
ADJUSTMENT TO:	Rate Base
DATE SUBMITTED:	October 10, 2015
PREPARED BY:	Rigo Ramirez
CHECKED BY:	
REVIEWED BY:	

		Total Company		ACC Jurisdictional	
FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT	DEBIT	CREDIT
N/A	Cash Working Capital		$10,734,427		$10,528,875
151, 152	Fuel Inventory		$5,021,076		$4,655,159
154, 163	Materials & Supplies		$10,110,914		$9,787,349
165	Prepaids		$2,399,972		$2,353,971
	ENTRY TOTAL	$0	$28,266,389	$0	$27,325,155
	NET ENTRY		$28,266,389		$27,325,155

Reason for Adjustment

Dept Corp Acct - GL - Balance - - - Acct, SubAcct Conditions: "Acct$UNS_GL_Account" = :Enter Account, "Acct$UNS_GL_Company" = :Enter Company, Summary_Flag = 'N', Currency_Code = 'USD', Period_Name = :Period Name, NOT (Balance SUM = 0 AND Begin_Balance SUM = 0 AND Period_Net SUM = 0 AND Period_Net_Dr SUM = 0 AND Parameters: Period Name : 'JUL-14, AUG-14, SEP-14, OCT-14, NOV-14, DEC-14, JAN-15, FEB-15, MAR-15, APR-15, MAY-15, JUN-15' , Company : '002' , Account : '12500, 12600' 05-OCT-15 - 03.16.29 PM

Acct	Acct Name	Period Name	Beginning Balance	Debits	Credits	Ending Balance
12500	Materials & Supplies	JUL-14	71,652,356.76	13,896,026.93	13,873,274.69	71,675,109.00
12600	Undistributed Stores Expense	JUL-14	7,756,470.37	1,278,155.90	1,151,850.24	7,882,776.03
12500	Materials & Supplies	AUG-14	71,675,109.00	22,867,708.83	21,400,324.50	73,142,493.33
12600	Undistributed Stores Expense	AUG-14	7,882,776.03	1,159,087.26	980,044.51	8,061,818.78
12500	Materials & Supplies	SEP-14	73,142,493.33	14,611,766.00	15,373,129.37	72,381,129.96
12600	Undistributed Stores Expense	SEP-14	8,061,818.78	1,321,931.35	1,290,799.75	8,092,950.38
12500	Materials & Supplies	OCT-14	72,381,129.96	16,351,535.62	15,653,747.32	73,078,918.26
12600	Undistributed Stores Expense	OCT-14	8,092,950.38	3,317,504.85	3,341,435.93	8,069,019.30
12500	Materials & Supplies	NOV-14	73,078,918.26	17,235,977.97	17,482,346.01	72,832,550.22
12600	Undistributed Stores Expense	NOV-14	8,069,019.30	10,124,352.34	10,348,944.06	7,844,427.58
12500	Materials & Supplies	DEC-14	72,832,550.22	37,173,104.58	31,084,561.78	78,921,093.02
12600	Undistributed Stores Expense	DEC-14	7,844,427.58	56,743,615.21	56,759,017.25	7,829,025.54
12500	Materials & Supplies	JAN-15	78,921,093.02	45,934,537.45	43,620,990.85	81,234,639.62
12600	Undistributed Stores Expense	JAN-15	7,829,025.54	48,603,539.47	49,318,377.46	7,114,187.55
12500	Materials & Supplies	FEB-15	81,234,639.62	12,615,825.82	12,159,705.35	81,690,760.09
12600	Undistributed Stores Expense	FEB-15	7,114,187.55	1,121,816.27	1,230,993.47	7,005,010.35
12500	Materials & Supplies	MAR-15	81,690,760.09	13,548,555.79	13,147,865.09	82,091,450.79
12600	Undistributed Stores Expense	MAR-15	7,005,010.35	1,238,193.28	1,292,176.63	6,951,027.00
12500	Materials & Supplies	APR-15	82,091,450.79	15,367,301.45	15,015,105.57	82,443,646.67
12600	Undistributed Stores Expense	APR-15	6,951,027.00	1,557,436.17	1,296,122.85	7,212,340.32
12500	Materials & Supplies	MAY-15	82,443,646.67	19,692,537.57	18,851,127.12	83,285,057.12
12600	Undistributed Stores Expense	MAY-15	7,212,340.32	1,168,714.51	1,633,573.94	6,747,480.89
12500	Materials & Supplies	JUN-15	83,285,057.12	15,794,223.74	16,263,586.16	82,815,694.70
12600	Undistributed Stores Expense	JUN-15	6,747,480.89	2,006,968.81	1,784,411.43	6,970,038.27
Grand Total			**1,014,995,738.93**	**374,730,417.17**	**364,353,511.33**	**1,025,372,644.77**

13-month balance	1,025,372,644.77
	13
13-month average balance	78,874,818.83
Balance per GL @ 06/30/15	89,785,732.97
	(800,000.00)
	88,985,732.97
Pro Forma Adjustment	**(10,110,914.14)** A

TEP(0322)003731

Docket No. E-01933A-15-0322
Attachment DHM-12
Page 2 of 3

Dept Corp Acct - GL - Balance - - - Acct, SubAcct Conditions: "Acct$UNS_GL_Account" = :Enter Account, "Acct$UNS_GL_Company" = :Enter Company, Summary_Flag = 'N', Currency_Code = 'USD', Period_Name = :Period Name, NOT (Balance SUM = 0 AND Begin_Balance SUM = 0 AND Period_Net SUM = 0 AND Period_Net_Dr SUM = 0 AND Parameters: Period Name : 'JUN-14, JUL-14, AUG-14, SEP-14, OCT-14, NOV-14, DEC-14, JAN-15, FEB-15, MAR-15, APR-15, MAY-15, JUN-15' , Company : '002' , Account : '14000, 14010, 14020, 14030, 14040, 14050, 14100' 05-OCT-15 - 03.41.07 PM

Acct	Acct Name	Period Name	Beginning Balance	Debits	Credits	Ending Balance
14010	Prepaid Insurance	JUN-14	3,190,619.99	0.00	665,344.67	2,525,275.32
14030	Prepaid Rent	JUN-14	523,001.05	0.00	83,625.98	439,375.07
14050	Prepaid Taxes	JUN-14	0.00	952,590.00	209,343.88	743,246.12
14100	Other Prepaids	JUN-14	6,215,917.58	746,562.92	1,019,417.91	5,943,062.59
14010	Prepaid Insurance	JUL-14	2,525,275.32	830,313.57	390,626.72	2,964,962.17
14030	Prepaid Rent	JUL-14	439,375.07	251,678.02	327,720.66	363,332.43
14050	Prepaid Taxes	JUL-14	743,246.12	0.00	0.00	743,246.12
14100	Other Prepaids	JUL-14	5,943,062.59	2,055,879.19	1,925,455.29	6,073,486.49
14010	Prepaid Insurance	AUG-14	2,964,962.17	158,680.76	999,141.61	2,124,501.32
14030	Prepaid Rent	AUG-14	363,332.43	216,839.03	131,070.13	449,101.33
14050	Prepaid Taxes	AUG-14	743,246.12	0.00	245,407.86	497,838.26
14100	Other Prepaids	AUG-14	6,073,486.49	1,519,966.06	937,957.29	6,655,495.26
14010	Prepaid Insurance	SEP-14	2,124,501.32	1,158,086.65	1,166,134.09	2,116,453.88
14030	Prepaid Rent	SEP-14	449,101.33	0.00	65,897.12	383,204.21
14050	Prepaid Taxes	SEP-14	497,838.26	0.00	453,645.74	44,192.52
14100	Other Prepaids	SEP-14	6,655,495.26	218,295.52	1,049,569.99	5,824,220.79
14010	Prepaid Insurance	OCT-14	2,116,453.88	61,743.37	402,700.39	1,775,496.86
14030	Prepaid Rent	OCT-14	383,204.21	162,848.67	80,701.55	465,351.33
14050	Prepaid Taxes	OCT-14	44,192.52	0.00	0.00	44,192.52
14100	Other Prepaids	OCT-14	5,824,220.79	290,697.25	850,968.04	5,263,950.00
14010	Prepaid Insurance	NOV-14	1,775,496.86	422,485.83	405,398.72	1,792,583.97
14030	Prepaid Rent	NOV-14	465,351.33	3,143.44	83,844.99	384,649.78
14050	Prepaid Taxes	NOV-14	44,192.52	0.00	44,192.52	0.00
14100	Other Prepaids	NOV-14	5,263,950.00	237,347.14	832,552.38	4,668,744.76
14010	Prepaid Insurance	DEC-14	1,792,583.97	182,956.18	277,770.05	1,697,770.10
14030	Prepaid Rent	DEC-14	384,649.78	0.00	80,701.64	303,948.14
14100	Other Prepaids	DEC-14	4,668,744.76	1,373,061.49	1,217,131.66	4,824,674.59
14010	Prepaid Insurance	JAN-15	1,697,770.10	1,274,712.30	813,619.63	2,158,862.77
14030	Prepaid Rent	JAN-15	303,948.14	1,122,424.09	158,718.52	1,267,653.71
14100	Other Prepaids	JAN-15	4,824,674.59	2,644,572.89	2,107,368.91	5,361,878.57
14010	Prepaid Insurance	FEB-15	2,158,862.77	51,826.15	383,996.08	1,826,692.84
14030	Prepaid Rent	FEB-15	1,267,653.71	77,908.16	606,828.04	738,733.83
14100	Other Prepaids	FEB-15	5,361,878.57	5,892,510.82	1,858,276.34	9,396,113.05
14010	Prepaid Insurance	MAR-15	1,826,692.84	127,844.70	383,996.09	1,570,541.45
14030	Prepaid Rent	MAR-15	738,733.83	7,169.87	126,964.83	618,938.87
14100	Other Prepaids	MAR-15	9,396,113.05	4,673,006.25	6,587,197.51	7,481,921.79
14010	Prepaid Insurance	APR-15	1,570,541.45	2,595,015.37	369,160.69	3,796,396.13
14030	Prepaid Rent	APR-15	618,938.87	82,811.80	131,509.38	570,241.29
14100	Other Prepaids	APR-15	7,481,921.79	7,628,119.45	7,303,233.94	7,806,807.30
14010	Prepaid Insurance	MAY-15	3,796,396.13	153,063.62	368,814.19	3,580,645.56
14030	Prepaid Rent	MAY-15	570,241.29	39,433.66	84,864.35	524,810.60
14100	Other Prepaids	MAY-15	7,806,807.30	3,296,439.84	3,832,307.14	7,270,940.00
14010	Prepaid Insurance	JUN-15	3,580,645.56	0.00	722,387.35	2,858,258.21
14030	Prepaid Rent	JUN-15	524,810.60	5,128.26	84,864.39	445,074.47
14050	Prepaid Taxes	JUN-15	0.00	1,229,609.40	207,575.09	1,022,034.31
14100	Other Prepaids	JUN-15	7,270,940.00	3,874,403.80	3,447,113.83	7,698,229.97
Grand Total			**123,013,072.31**	**45,619,175.52**	**43,525,117.18**	**125,107,130.65**

13-month balance	$125,107,130.65
	13
13-month average balance	$9,623,625
Balance per GL @ 06/30/15	$12,023,597
Pro Forma Adjustment	**($2,399,972)** A

4

TUCSON ELECTRIC POWER COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2015

ADJUSTMENT NAME:	Working Capital
ADJUSTMENT TO:	Rate Base
DATE SUBMITTED:	March 9, 2016
PREPARED BY:	Rigo Ramirez
CHECKED BY:	
REVIEWED BY:	David Lewis

		Total Company		ACC Jurisdictional	
FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT	DEBIT	CREDIT
N/A	Cash Working Capital		$10,743,700		$10,537,771
151, 152	Fuel Inventory		$5,021,076		$4,855,159
154, 163	Materials & Supplies		4,802,543		$4,648,854
165	Prepaids		$2,399,972		$2,353,971
	ENTRY TOTAL	$0	$22,967,291	$0	$22,195,755
	NET ENTRY		$22,967,291		$22,195,755

Tucson Electric Power
Fuel Inventory - Burn Rate Average Balance
As of June, 30, 2015

Calculation for Targeted Levels

Acct	Plant Description	Target Inventory Days	Target Inventory Tons	Inventory Cost
COAL:				
12000	San Juan U1 & U2	40	155,288	9,222,554
12000	Less: San Juan U2	-	(77,644)	(4,611,277)
12000	Navajo	30	49,664	2,067,512
12000	Springerville	40	400,000	15,628,000
12000	Sundt	-	-	-
				22,306,789
OIL:				
12010	SPV Oil U1 & U2		700,000	2,254,000

Notes:
Target Oil inventory information is available for Springerville. All other oil target inventory balanc

GL Balance	Pro Forma
9,116,952	105,602
-	(4,611,277)
2,405,589	(338,077)
15,491,949	136,051
1,238,525	(1,238,525)
28,253,015	(5,946,226)
1,328,850	925,150
Pro-Forma	(5,021,076)

ıtory balances are expected to have small variations.

Dept Corp Acct - GL - Balance - - - Acct, SubAcct Conditions: "Acct$UNS_GL_Account" = :Enter Account, "Acct$UNS_GL_Company" = :Enter Company, Summary_Flag = 'N', Currency_Code = 'USD', Period_Name = :Period Name, NOT (Balance SUM = 0 AND Begin_Balance SUM = 0 AND Period_Net SUM = 0 AND Period_Net_Dr SUM = 0 AND Parameters: Period Name : 'JUL-14, AUG-14, SEP-14, OCT-14, NOV-14, DEC-14, JAN-15, FEB-15, MAR-15, APR-15, MAY-15, JUN-15' , Company : '002' , Account : '12500, 12600' 05-OCT-15 - 03.16.29 PM

Acct	Acct Name	Period Name	Beginning Balance	Debits	Credits	Ending Balance
12500	Materials & Supplies	JUL-14	71,652,356.76	13,896,026.93	13,873,274.69	71,675,109.00
12600	Undistributed Stores Expense	JUL-14	7,756,470.37	1,278,155.90	1,151,850.24	7,882,776.03
12500	Materials & Supplies	AUG-14	71,675,109.00	22,867,708.83	21,400,324.50	73,142,493.33
12600	Undistributed Stores Expense	AUG-14	7,882,776.03	1,159,067.26	980,044.51	8,061,818.78
12500	Materials & Supplies	SEP-14	73,142,493.33	14,611,766.00	15,373,129.37	72,381,129.96
12600	Undistributed Stores Expense	SEP-14	8,061,818.78	1,321,931.35	1,290,799.75	8,092,950.38
12500	Materials & Supplies	OCT-14	72,381,129.96	16,351,535.62	15,653,747.32	73,078,918.26
12600	Undistributed Stores Expense	OCT-14	8,092,950.38	3,317,504.85	3,341,435.93	8,069,019.30
12500	Materials & Supplies	NOV-14	73,078,918.26	17,235,977.97	17,482,346.01	72,832,550.22
12600	Undistributed Stores Expense	NOV-14	8,069,019.30	10,124,352.34	10,348,944.06	7,844,427.58
12500	Materials & Supplies	DEC-14	72,832,550.22	37,173,104.58	31,084,561.78	78,921,093.02
12600	Undistributed Stores Expense	DEC-14	7,844,427.58	56,743,615.21	56,759,017.25	7,829,025.54
12500	Materials & Supplies	JAN-15	78,921,093.02	45,934,537.45	43,620,990.85	81,234,639.62
12600	Undistributed Stores Expense	JAN-15	7,829,025.54	48,603,539.47	49,318,377.46	7,114,187.55
12500	Materials & Supplies	FEB-15	81,234,639.62	12,615,825.82	12,159,705.35	81,690,760.09
12600	Undistributed Stores Expense	FEB-15	7,114,187.55	1,121,816.27	1,230,993.47	7,005,010.35
12500	Materials & Supplies	MAR-15	81,690,760.09	13,548,555.79	13,147,865.09	82,091,450.79
12600	Undistributed Stores Expense	MAR-15	7,005,010.35	1,238,193.28	1,292,176.63	6,951,027.00
12500	Materials & Supplies	APR-15	82,091,450.79	15,367,301.45	15,015,105.57	82,443,646.67
12600	Undistributed Stores Expense	APR-15	6,951,027.00	1,557,436.17	1,296,122.85	7,212,340.32
12500	Materials & Supplies	MAY-15	82,443,646.67	19,682,537.57	18,851,127.12	83,285,057.12
12600	Undistributed Stores Expense	MAY-15	7,212,340.32	1,168,714.51	1,633,573.94	6,747,480.89
12500	Materials & Supplies	JUN-15	83,285,057.12	15,794,223.74	16,263,586.16	82,815,694.70
12600	Undistributed Stores Expense	JUN-15	6,747,480.89	2,006,968.81	1,784,411.43	6,970,038.27
Grand Total			**1,014,995,738.93**	**374,738,417.17**	**364,353,511.33**	**1,025,372,644.77**

13-month balance	1,025,372,644.77
	13
13-month average balance	78,874,818.83
Balance per GL @ 06/30/15	89,785,732.97
	(800,000.00)
	88,985,732.97
Pro Forma Adjustment	**(10,110,914.14)**

Dept Corp Acct - GL - Balance - - - Acct, SubAcct Conditions: "Acct$UNS_GL_Account" = :Enter Account, "Acct$UNS_GL_Company" = :Enter Company, Summary_Flag = 'N', Currency_Code = 'USD', Period_Name = :Period Name Parameters: Period Name : 'JUN-14, JUL-14, AUG-14, SEP-14, OCT-14, NOV-14, DEC-14, JAN-15, FEB-15, MAR-15, APR-15, MAY-15, JUN-15' , Company : '002' , Account : '12500, 12600' 09-MAR-16 - 11.26.07 AM

Acct	Acct Name	Period Name	Beginning Balance	Debits	Credits	Ending Balance	Sundt & San Juan M&S	Adjusted Balance
12500	Materials & Supplies	JUN-14	70,450,900.32	14,902,669.63	13,701,213.19	71,652,356.76	(1,225,594.00)	70,426,762.76
12600	Undistributed Stores Expense	JUN-14	7,870,093.36	905,116.56	818,739.55	7,756,470.37	-	7,756,470.37
12500	Materials & Supplies	JUL-14	71,652,356.76	13,896,026.93	13,873,274.69	71,675,109.00	(1,225,594.00)	70,449,515.00
12600	Undistributed Stores Expense	JUL-14	7,756,470.37	1,276,155.90	1,151,850.24	7,882,776.03	-	7,882,776.03
12500	Materials & Supplies	AUG-14	71,675,109.00	22,867,708.83	21,400,324.50	73,142,493.33	(1,225,594.00)	71,916,899.33
12600	Undistributed Stores Expense	AUG-14	7,882,776.03	1,159,067.26	980,044.51	8,061,818.78	-	8,061,818.78
12500	Materials & Supplies	SEP-14	73,142,493.33	14,611,765.00	15,373,129.37	72,381,129.96	(1,225,594.00)	71,155,535.96
12600	Undistributed Stores Expense	SEP-14	8,061,818.78	1,321,931.35	1,290,799.75	8,092,950.38	-	8,092,950.38
12500	Materials & Supplies	OCT-14	72,381,129.96	16,351,535.82	15,653,747.32	73,078,918.26	(1,225,594.00)	71,853,324.26
12600	Undistributed Stores Expense	OCT-14	8,092,950.38	3,317,504.85	3,341,435.93	8,069,019.30	-	8,069,019.30
12500	Materials & Supplies	NOV-14	73,078,918.26	17,235,977.97	17,482,346.01	72,832,550.22	(1,225,594.00)	71,606,956.22
12600	Undistributed Stores Expense	NOV-14	8,069,019.30	10,124,352.34	10,346,944.06	7,844,427.58	-	7,844,427.58
12500	Materials & Supplies	DEC-14	72,832,550.22	37,173,104.58	31,084,561.78	78,921,093.02	(1,225,594.00)	77,695,499.02
12600	Undistributed Stores Expense	DEC-14	7,844,427.58	56,743,815.21	56,759,017.25	7,829,025.54	-	7,829,025.54
12500	Materials & Supplies	JAN-15	78,921,093.02	45,934,537.45	43,620,990.85	81,234,639.62	(1,225,594.00)	80,009,045.62
12600	Undistributed Stores Expense	JAN-15	7,829,025.54	48,603,539.47	48,318,377.46	7,114,187.55	-	7,114,187.55
12500	Materials & Supplies	FEB-15	81,234,639.62	12,615,825.82	12,159,705.35	81,690,760.09	(1,225,594.00)	80,465,166.09
12600	Undistributed Stores Expense	FEB-15	7,114,187.55	1,121,816.27	1,230,993.47	7,005,010.35	-	7,005,010.35
12500	Materials & Supplies	MAR-15	81,690,760.09	13,548,555.79	13,147,865.09	82,091,450.79	(1,225,594.00)	80,865,856.79
12600	Undistributed Stores Expense	MAR-15	7,005,010.35	1,238,193.28	1,292,176.63	6,951,027.00	-	6,951,027.00
12500	Materials & Supplies	APR-15	82,091,450.79	15,367,301.45	15,015,105.57	82,443,646.67	(1,225,594.00)	81,218,052.67
12600	Undistributed Stores Expense	APR-15	6,951,027.00	1,557,436.17	1,296,122.65	7,212,340.32	-	7,212,340.32
12500	Materials & Supplies	MAY-15	82,443,646.67	19,692,537.57	18,851,127.12	83,285,057.12	(1,225,594.00)	82,059,463.12
12600	Undistributed Stores Expense	MAY-15	7,212,340.32	1,168,714.51	1,633,573.94	6,747,480.89	-	6,747,480.89
12500	Materials & Supplies	JUN-15	83,285,057.12	15,794,223.74	16,263,586.16	82,815,694.70	(1,225,594.00)	81,590,100.70
12600	Undistributed Stores Expense	JUN-15	6,747,480.89	2,006,968.81	1,784,411.43	6,970,038.27	-	6,970,038.27
Grand Total			1,093,116,732.61	396,536,283.36	378,873,464.87	1,194,781,471.98	<15,932,722.08>	1,088,848,749.90

13-month balance	1,088,848,749.90
	13
13-month average balance	83,757,596.15
Balance per GL @ 06/30/15	88,560,138.97
Pro Forma Adjustment	(4,802,542.82)

Dept Corp Acct - GL - Balance - - - Acct, SubAcct Conditions: "Acct$UNS_GL_Account" = :Enter Account, "Acct$UNS_GL_Company" = :Enter Company, Summary_Flag = 'N', Currency_Code = 'USD', Period_Name = :Period Name, NOT (Balance SUM = 0 AND Begin_Balance SUM = 0 AND Period_Net SUM = 0 AND Period_Net_Dr SUM = 0 AND Parameters: Period Name : 'JUN-14, JUL-14, AUG-14, SEP-14, OCT-14, NOV-14, DEC-14, JAN-15, FEB-15, MAR-15, APR-15, MAY-15, JUN-15' , Company : '002' , Account : '14000, 14010, 14020, 14030, 14040, 14050, 14100' 05-OCT-15 - 03.41.07 PM

Acct	Acct Name	Period Name	Beginning Balance	Debits	Credits	Ending Balance
14010	Prepaid Insurance	JUN-14	3,190,619.99	0.00	665,344.67	2,525,275.32
14030	Prepaid Rent	JUN-14	523,001.05	0.00	83,625.98	439,375.07
14050	Prepaid Taxes	JUN-14	0.00	952,590.00	209,343.88	743,246.12
14100	Other Prepaids	JUN-14	6,215,917.58	746,562.92	1,019,417.91	5,943,062.59
14010	Prepaid Insurance	JUL-14	2,525,275.32	830,313.57	390,626.72	2,964,962.17
14030	Prepaid Rent	JUL-14	439,375.07	251,678.02	327,720.66	363,332.43
14050	Prepaid Taxes	JUL-14	743,246.12	0.00	0.00	743,246.12
14100	Other Prepaids	JUL-14	5,943,062.59	2,055,879.19	1,925,455.29	6,073,486.49
14010	Prepaid Insurance	AUG-14	2,964,962.17	158,680.76	999,141.61	2,124,501.32
14030	Prepaid Rent	AUG-14	363,332.43	216,839.03	131,070.13	449,101.33
14050	Prepaid Taxes	AUG-14	743,246.12	0.00	245,407.86	497,838.26
14100	Other Prepaids	AUG-14	6,073,486.49	1,519,966.06	937,957.29	6,655,495.26
14010	Prepaid Insurance	SEP-14	2,124,501.32	1,158,086.65	1,166,134.09	2,116,453.88
14030	Prepaid Rent	SEP-14	449,101.33	0.00	65,897.12	383,204.21
14050	Prepaid Taxes	SEP-14	497,838.26	0.00	453,645.74	44,192.52
14100	Other Prepaids	SEP-14	6,655,495.26	218,295.52	1,049,569.99	5,824,220.79
14010	Prepaid Insurance	OCT-14	2,116,453.88	61,743.37	402,700.39	1,775,496.86
14030	Prepaid Rent	OCT-14	383,204.21	162,848.67	80,701.55	465,351.33
14050	Prepaid Taxes	OCT-14	44,192.52	0.00	0.00	44,192.52
14100	Other Prepaids	OCT-14	5,824,220.79	290,697.25	850,968.04	5,263,950.00
14010	Prepaid Insurance	NOV-14	1,775,496.86	422,485.83	405,398.72	1,792,583.97
14030	Prepaid Rent	NOV-14	465,351.33	3,143.44	83,844.99	384,649.78
14050	Prepaid Taxes	NOV-14	44,192.52	0.00	44,192.52	0.00
14100	Other Prepaids	NOV-14	5,263,950.00	237,347.14	832,552.38	4,668,744.76
14010	Prepaid Insurance	DEC-14	1,792,583.97	182,956.18	277,770.05	1,697,770.10
14030	Prepaid Rent	DEC-14	384,649.78	0.00	80,701.64	303,948.14
14100	Other Prepaids	DEC-14	4,668,744.76	1,373,061.49	1,217,131.66	4,824,674.59
14010	Prepaid Insurance	JAN-15	1,697,770.10	1,274,712.30	813,619.63	2,158,862.77
14030	Prepaid Rent	JAN-15	303,948.14	1,122,424.09	158,718.52	1,267,653.71
14100	Other Prepaids	JAN-15	4,824,674.59	2,644,572.89	2,107,368.91	5,361,878.57
14010	Prepaid Insurance	FEB-15	2,158,862.77	51,826.15	383,996.08	1,826,692.84
14030	Prepaid Rent	FEB-15	1,267,653.71	77,908.16	606,828.04	738,733.83
14100	Other Prepaids	FEB-15	5,361,878.57	5,892,510.82	1,858,276.34	9,396,113.05
14010	Prepaid Insurance	MAR-15	1,826,692.84	127,844.70	383,996.09	1,570,541.45
14030	Prepaid Rent	MAR-15	738,733.83	7,169.87	126,964.83	618,938.87
14100	Other Prepaids	MAR-15	9,396,113.05	4,673,006.25	6,587,197.51	7,481,921.79
14010	Prepaid Insurance	APR-15	1,570,541.45	2,595,015.37	369,160.69	3,796,396.13
14030	Prepaid Rent	APR-15	618,938.87	82,811.80	131,509.38	570,241.29
14100	Other Prepaids	APR-15	7,481,921.79	7,628,119.45	7,303,233.94	7,806,807.30
14010	Prepaid Insurance	MAY-15	3,796,396.13	153,063.62	368,814.19	3,580,645.56
14030	Prepaid Rent	MAY-15	570,241.29	39,433.66	84,864.35	524,810.60
14100	Other Prepaids	MAY-15	7,806,807.30	3,296,439.84	3,832,307.14	7,270,940.00
14010	Prepaid Insurance	JUN-15	3,580,645.56	0.00	722,387.35	2,858,258.21
14030	Prepaid Rent	JUN-15	524,810.60	5,128.26	84,864.39	445,074.47
14050	Prepaid Taxes	JUN-15	0.00	1,229,609.40	207,575.09	1,022,034.31
14100	Other Prepaids	JUN-15	7,270,940.00	3,874,403.80	3,447,113.83	7,698,229.97
Grand Total			**123,013,072.31**	**45,619,175.52**	**43,525,117.18**	**125,107,130.65**

13-month balance	$125,107,130.65
	13
13-month average balance	$9,623,625
Balance per GL @ 06/30/15	$12,023,597
Pro Forma Adjustment	**($2,399,972)**

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 21, 2016

STF 7.21

Sundt and San Juan M&S Adjustment:

Reference UDR 1.001 WP and Company witness Marino direct testimony page 14 and 42. The Company proposes to record any remaining inventory from Sundt and San Juan Unit 2 to a regulatory asset FERC 182.3 (Other Regulatory Assets), and amortize the cost over a 3-year term. The total amortization is $1,225,594 and the annual amortization is $408,531 and will be charged to FERC 407.3 (regulatory debits).

a. Are any of the proposed regulatory assets spare parts that have been capitalized as capital spares?

b. Company witness Marino indicates that the M&S for Sundt Unit 4 had it been installed would have been recovered as depreciation expense charged to fuel. Is any of the inventory excess?

c. Was any of the Sundt M&S considered critical to the operation of Unit 4 and had to be purchased?

d. Will the San Juan remaining inventory change as a result of utilization at Unit 1 and if so how will that be accounted for?

e. Is any of the M&S included in rates? If so, please indicate the amount.

f. Why should the customer pay for M&S that is excess or obsolete and will not provide any benefit to them?

RESPONSE:

a. No.

b. The inventory was acquired to ensure the reliable operation of the assets. Such inventory is subject to annual assessments of and adjustments to inventory levels for obsolete or excess inventory. Thus, the remaining inventory proposed to be recovered is not excess.

c. The Sundt coal materials and supplies consists of spare parts and materials needed to ensure reliable operation of Unit 4.

d. The proposed adjustment includes only the inventory specific to San Juan Unit 2 given its turbine technology. The inventory that is suitable for use on San Juan Unit 1 will follow existing inventory accounting processes and is not subject to the proposed three-year amortization.

e. The Company inadvertently did not make the correct adjustment to reduce the M&S amount reflected in working capital in its initial filing. In the Company's filing, only $800K was used to reduce material and supplies related to Sundt and San Juan. Also, there was a mathematical error in the original pro-forma. Once these errors are corrected, the company Revenue Requirement would increase by roughly $500K. Please see "Rate Base – Working Capital Revised.xlsm" provided in UDR 1.001.

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 21, 2016

f. The closure of both San Juan Unit 2 and Sundt Unit 4 coal dedicated facilities and equipment were driven by external factors as described in Mr. Marino's testimony. TEP maintained an appropriate level of inventory for parts to ensure reliable operation of the plants. TEP acted reasonably and was prudent with inventory purchase decisions.

RESPONDENT:

Aaron Groff

WITNESS:

Frank Marino

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S TENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 7, 2016

STF 10.02

CASH WORKING CAPITAL – SCHEDULE B-5: Please explain the increase in the following items listed on Schedule B-5 when compared to similar information contained in Schedule B-2 of the Company's filing in E-01933A-12-0291.

a. Line 10 – Office Supplies and Expenses $11,750,832 (compared to Line 6 in Schedule B-2 in 12-0291 - $9,594,745)
b. Line 11 – Outside services $12,768,854 (compared to line 7 $10,520,391)
c. Line 17 – Property Taxes $46,931,391 (compared to line 13 $39,148,092)
d. Line 18 – Payroll Taxes $10,391,284 (compared to line 14 $7,830,466)
e. Line 22 – Other Operations and Maintenance Expenses $76,989,263 (compared to line 18 $63,312,707

RESPONSE:

The Company wishes to point out that total Operating Expense (excluding income taxes) requested in the current rate case is $795,193,802 versus $795,077,661 in the previous rate case. An increase of only 0.01%. Highlighting and reviewing those areas that have increased may not give a complete picture of the operating cost changes since the last rate case.

a The increase Office Supplies and Expenses is primarily related to an increase in computer hardware and software expenses, building allocations, and travel and training expenses.

b. Increase in Outside Services is primarily related to increases in Legal Fees and Corporate Security. In the prior rate case, Corporate Security expenses were charged to a clearing account then spread over a number of accounts. In the first quarter of 2015, expenses for Corporate Security are charged directly to outside services.

c. The increase is primarily related to a $73 million increase in taxable property values and an increase in average Arizona tax rates from 10.1435% in the last rate case vs 11.1865% in the current rate case.

d. Upon review of the increase in payroll taxes, it was discovered that there was a formula error in the current 2015 rate case payroll tax case number. Payroll Taxes on Column B Line 18 should be $8,752,492 resulting in a $922,026 increase in payroll taxes from the prior rate case which is in line with average wage increases since the last rate case.

e. The Company objects to this question as to determine the cause of the increase would be overly burdensome and a time consuming task considering that it is such a de minimis amount of 0.01%. Without waiver of objections, other Operations and Maintenance Expense is a combination of all other expenses not specifically identified in the Cash Working Capital Schedule B-5.

RESPONDENT:

Rigo Ramirez

WITNESS:

Dallas Dukes

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S TENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 7, 2016

STF 10.03

CASH WORKING CAPITAL – SCHEDULE B-5: Please confirm that the calculation of net lag days (Col e) on page 3 of 3 is not correct. For example, Line 5 – revenue lag for Salaries (Col C) is 38.62 less the Expense Lag of 10.46 in Col (D) should result in a net lag days of 28.16 (not 26.01 as shown in Col E). Please confirm however that a: the Lead/Lag factor in Col F is correctly calculated based on Col C and D and b: that the CWC Required in COL G is what the Company intended to include in the filing.

RESPONSE:

The calculation of net lag days (Col E) is not correct except for lines 22, 24 and 25. The formulas which pulled this data is linked to the wrong worksheet. The Company confirms that the Lead/Lag factor in Col F is correctly calculated based on Col C and D and that the CWC Required in COL G is what the Company intended to include in the filing.

RESPONDENT:

Rigo Ramirez

WITNESS:

Dallas Dukes

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FOURTEENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 25, 2016

STF 14.01

Follow-up to STF 10.02 response to d. – Cash Working Capital. Please provide the specific calculations and references so as to allow Staff to validate the stated error to Payroll Taxes. Does the company intend to submit an errata sheet with this correction?

RESPONSE:

Please see attached Excel file name STF 14.01 Worksheet.xlsx and PDF file name STF 14.01 Worksheet and Supporting Documents.pdf for the revised Payroll Tax calculations. The Company intends to submit corrected schedules as part of TEP's Rebuttal testimony.

RESPONDENT:

Rigo Ramirez

WITNESS:

Dallas Dukes

Tucson Electric Power Company
Payroll Tax Expense
STF 14.01

	Ref.	As Filed Test Year Ended 6/30/2015	Ref.	Revised Test Year Ended 6/30/2015	Ref.	Prior Test Year Ended 12/31/2011
TEP Employer Tax	1a	10,494,500	1a	10,494,500	5a	9,481,829
Allocation % of Payroll Charged to Clearing Accounts	2.1a	0.6640	2.1a	0.6640	6a	0.6531
Annualized O&M Payroll Taxes	Error	8,606,720		6,967,928		6,192,583
Payroll Taxes Included in Incentive Comp Adjustment	3a	566,200	3a	566,200	7a	468,592
Payroll Tax Charges from the Remotes:						
Four Corners	4a	193,066	4a	193,066	8a	153,017
Navajo	4b	397,757	4b	397,757	8b	321,439
San Juan	4c	615,725	4c	615,725	8c	694,836
Luna	4d	11,315	4d	11,315		-
Gila River	4e	501	4e	501		-
Payroll Taxes - Schedule B, Line 18	9a	10,391,284		8,752,492		7,830,467

TUCSON ELECTRIC POWER COMPANY
Payroll Tax Expense
Test Year Ended June 30, 2015

TEP Employer Tax - Ended June 2015		
Social Security	7,900,994	per Form 941
Medicare	2,450,273	per Form 941
FUTA/SUTA	143,232	per FUTA and SUTA returns
	10,494,500	

	Wages, tips and other compensation from Form 941	
Q3 2014	62,328,958	
Q4 2014	35,209,774	
Q1 2015	27,716,883	
Q2 2015	33,876,917	
	159,132,532	0.066 effective tax rate (A)

Payroll Adjustment	2,729,720	(B) (from Payroll Expense Adj)
Employer Payroll Tax Adjustment	$ 180,020	(A) X (B)

10,494,500 ·
0·66396
6,967,928·22

Source: TEP Payroll Tax Expense
2015 Pro Forma Adjustment

Tucson Electric Power Company
2014 FERC Form 1 Pages 354-355 Allocation Worksheet

Source: FERC FORM 1 2014 workpapers

UNS Massachusetts 3-Factor Formula Allocation Percentages:

TEP	7.2	80.46%
Affiliates		19.54%
		100.00%

Note: Acct 0163 is being allocated based on the percentage of materials issued to the respective FERC accounts. See attached Query results for percentage backup for each FERC account.

			%'s for Allocation of Acct 0163		Initial Clearing Acct Balances		Allocation of Acct 0163	Allocation of Acct 0184	UNS Allocation of Acct 0146	Total Allocation Adjustment	
Construction 0107		6	0.91572				2,138,338.64	3,821,773.13		5,960,110.77	1.1
Plant Removal 0108		6	-0.14561				(340,027.40)	58,477.70		(281,549.71)	1.1
	143 Other Accounts Receivable	6	0.00187				4,355.56	0.00		4,355.56	1.1
	146 Intercompany AR						0.00	643,502.51	1,209,967.66	1,853,470.17	s
	146 Intercompany AR - UNS Allocation			7.1b	5,436,516.52	p	0.00	755,743.74	(6,192,260.26)		
	151 Fuel Stock						0.00	17.03		17.03	1.1
	152 Coal Handling						0.00	81,216.81		81,216.81	1.1
	154 Materials and Operating Supplies						0.00	0.00		-	1.1
	163 Stores Expense			7.1f	2,335,135.89	q	(2,335,135.89)				
	182 Other Regulatory Assets						0.00	0.00		-	
	183 Preliminary Engineering						0.00	(3,564.31)		(3,564.31)	1.1
	184 Clearing Accounts	6	-0.00016	7.1l	16,060,459.42	r	(381.57)	o (16,060,077.85)			
	186 Miscellaneous Deferred Debits						0.00	4,015.72		4,015.72	1.1
	188 Research & Development						0.00	0.00		-	
	416 Merchandising Expense						0.00	0.00		-	1.1
	417 Non-Utility Income & Expense	6	0.00436				10,191.66	32,146.88		42,338.55	1.1
	426 Other Deductions	6	0.00008				185.74	3,524.58		3,710.32	1.1
	O&M	6	0.22374				522,473.26	10,663,224.05	4,982,292.61	16,167,988.92	1
			1.00000		23,832,111.83		0.00	0.00	0.00	23,832,109.83	

Per P. McKee:
Allocation of Acct 0184 should be based upon relative amounts in all payroll salary and wage accounts (exclusive of 0163 and 0184).

			%'s for Allocation of Acct 0184		
O&M	2.1	76,706,944.77	0.66396	(a)	10,663,224.05
Construction	2.1	27,492,298.69	0.23797		3,821,773.13
Removal	2.1	420,665.02	0.00364		58,477.70
143 Other Accounts Receivable	7.1a	-	0.00000		0.00
146 Intercompany AR	2.2	4,629,098.22	0.04007		643,502.51
146 Intercompany AR - UNS Allocation	7.1b	5,436,516.52	0.04706		755,743.74
151 Fuel Stock	7.1c	122.54	0.00000		17.03
152 Coal Handling	7.1d	584,241.09	0.00506		81,216.81
154 Materials and Operating Supplies	7.1e	-	0.00000		0.00
182 Other Regulatory Assets	7.1g	-	0.00000		0.00
183 Preliminary Engineering	7.1h	(25,640.21)	-0.00022		(3,564.31)
186 Miscellaneous Deferred Debits	7.1j	28,887.48	0.00025		4,015.72
188 Research & Development	7.1k	-	0.00000		0.00
416 Merchandising Expense	7.1l	-	0.00000		0.00
417 Non-Utility Income & Expense	7.1m	231,251.72	0.00200		32,146.88
426 Other Deductions	7.1n	25,354.39	0.00022		3,524.58
Total		115,529,740.23	1.00000		16,060,077.85

Reconciliation:
Total Salaries & Wages - FERC pg.355 2.2 144,321,739.15

G:\Corpacct\FERC\2014\Form 1\TEP\WP\Pages 354-355\TEP FERC Form 1 pg 354-355.xlsm

2.

Less: Incentive Compensation	-4.2a - 5a	(10,396,403.61)	
146 Intercompany AR	-2.2	(4,629,098.22)	
146 Intercompany AR - UNS Alloc	-b	(5,436,516.52)	
151 Fuel Stock	-c	(122.54)	
152 Coal Handling	-d	(584,241.09)	
163 Stores Expense	-f	(2,335,135.89)	
183 Preliminary Engineering	-h	25,640.21	
184 Clearing Accounts	-i	(16,060,459.42)	
186 Misc Deferred Debits	-j	(28,887.48)	
417 Non-Utility Income & Expense	-m	(231,251.72)	
426 Other Deductions	-n	(25,354.39)	
	2.1	104,619,908.48	<—Payroll by Function FSG Total Electric Payroll
0184 Acct to be Allocated:			
Direct 0184	i	16,060,459.42	
Allocated from 0163	7o	(381.57)	see above allocation of 0163 to 0184
		16,060,077.85	

Other Accounts:

FERC Account Per FERC P354		Amount	
FSG Report:			
143 Other Accounts Receivable	3	0.00	a
146 Intercompany AR - UNS Alloc		5,436,516.52	b
151 Fuel Stock		122.54	c
152 Coal Handling		584,241.09	d
154 Materials and Operating Supplies		0.00	e
163 Stores Expense		2,335,135.89	f
182 Other Regulatory Assets		0.00	g
183 Preliminary Engineering		-25,640.21	h
184 Clearing Accounts		16,060,459.42	i
185 Temporary Facilities		0.00	
186 Miscellaneous Deferred Debits		28,887.48	j
188 Research & Development		0.00	k
416 Merchandising Expense		0.00	l
417 Non-Utility Income & Expense		231,251.72	m
418 Nonoperating Rental Income		0.00	
426 Other Deductions		25,354.39	n
		24,676,328.84	

Procedures for Allocating Payroll Charged to Clearing Accts (0163 & 0184):

1. Run a Query on Materials Issued by FERC Acct.

2. Calculate %'s for each FERC account group (relative materials issued).

3. Allocate total costs in 0163 (Stores Expense) to all other accounts (including 0184) based on these %'s.

4. Allocate 0184 costs (including allocation from 0163) into O&M, Construction, Removal and other components based on Payroll by Function FSG.

5. Total adjustments by account and post to FERC Form 1 pages 354-355.

TEP(0322)022160

Docket No. E-01933A-15-0322
Attachment DHM-16
STF 14.01 Worksheet and Supporting Documents.pdf Page 5 of 12

2.

TUCSON ELECTRIC POWER CO.
INCENTIVE COMPENSATION EXPENSE
7/1/2013-6/30/14, 7/1/14-6/30/15 Pro Forma Adjustments

	7/1/13-6/30/14	7/1/14-6/30/15	2 Yr Average	7/1/14-6/30/15 Test Year	Difference
0408	569,673.18	562,726.88	566,200.03 (a)	527,194.00	39,006.03
0500	160,748.25	146,843.01	153,795.63	109,412.00	44,383.63
0506	1,833,265.09	1,688,920.45	1,761,092.77	1,283,253.00	477,839.77
0514	679,930.32	656,358.14	668,144.23	498,759.00	169,385.23
0566	1,256,695.43	1,037,909.89	1,147,302.66	751,760.00	395,542.66
0570	113,929.71	82,432.73	98,181.22	59,125.00	39,056.22
0580	4,596.96	-	2,298.48	-	2,298.48
0588	421,830.09	467,596.93	444,713.51	370,190.00	74,523.51
0598	107,572.88	118,477.83	113,025.36	93,479.00	19,546.36
0903	334,229.92	255,834.86	295,032.39	197,685.00	97,347.39
0920	3,881,601.69	3,964,666.49	3,923,134.09	4,095,263.00	(172,128.91)
	9,364,073.53	8,981,767.21	9,172,920.37	7,986,120.00	1,186,800.37
check nontax	8,794,400.35	8,419,040.33	8,606,720.34		
nonofficers	7,334,422.07	7,168,566.62	7,251,494.35		
0.0765	561,083.29	548,395.35	554,739.32		
check tax	8,589.89	14,331.53	11,460.71	pass	

TEP(0322)022161

3 Source:

G:\RATES\Rate Case 2015 TEP\Pro Forma Adjustments\Filed\Income - Short Term Incentive Compensation.xlsm, ProForma Adjust

REMOTE GENERATING STATIONS
TEST YEAR ENDING JUNE 30, 2015

Acct	Descriptions	1 Four Corners	2 Navajo	3 100% San Juan	4 50% San Juan U1	5 Luna	6 Gila River	7 w/o San Juan U2 Total
500	Steam Prod Oper-Supervision	353,354	1,485 957	1,603,355	801,678	981	0	2,641,969
501	Fuel - Steam	13,707,572	26,139 571	63 045,958	31,522,979	0	0	71,370,122
502	Steam Expense	1,663,885	980 886	2 171,136	1,085,568	0	0	3,730,339
505	Electric Expense	167,387	632 789	1,343,748	671,874	0	0	1,472,030
506	Steam Prod-Misc Expense	593,258	797 970	812,599	406,299	0	0	1,797,528
507	Rent	92,756	2,167 444	0	0	0	0	2,260,200
510	Maint-Supervision & Engr	266,681	529 102	1,592 599	796,299	0	0	1,592,092
511	Maint of Structures	189,635	144 368	1 642,951	821,481	0	0	1,155,484
512	Maint of Boiler Plant	3,605,414	2,914 600	9,423 542	4,711 771	0	0	11,231,785
513	Steam Prod-Mnt Elect Plant	504,950	1,338 421	1,462,844	731,422	0	0	2,574,794
514	Steam Prod-Mnt M sc Plant	1,175,204	343 861	1,054 454	527,227	0	0	2,046,293
546	Other Prod Oper-Supervision	0	0	0	0	5,579,357	981,545	6,560,902
547	Fuel - Other Pwr Generation	0	0	0	0	17,558,302	20,703 436	38,261,738
548	Generation Expense	0	0	0	0	6,528	445,466	452,022
549	Misc Other Pw Gen Exp	0	0	0	0	1,615	111,141	112,756
552	Maint of Structures	0	0	0	0	0	89,356	89,356
553	Maint Gen & Elec Plant	0	0	0	0	(45,053)	1,898,106	1,853,053
555	Purchased Power	0	0	0	0	0	91,747	91,747
556	System Control and Load Dispatching	91,533	17,888	297,455	148,728	164,107	0	422,055
560	Operation Supervision & Engineering	230	0	404	202	382	8,777	9,591
561	Load Dispatch	0	0		0	0	0	0
562	Trans-Load Dispatch	989	0	13,463	6,731	0	0	7,721
568	Maintenance Supervision & Engineering	766	0	0	0	0	0	766
570	Maintenance of Station Equipment	14,148	0	39,155	19,577	0	(3,583)	30,142
573	Trans-Maint Supv & Engr	0		0	0	0	0	0
920	A&G Salaries	0	0	1,346,902	673,451	0	4,010	677,461
921	Office Supplies/Expense	0	2,014,890	300,271	150 136	42 345	45,070	2,252,441
923	Outside Services	0	0	537,078	268 539	6	193,808	462,355
924	Property Insurance	(73,448)	129,305	340,228	170 114	80,469	40,470	348,909
925	Injuries and Damages	261,436	85,840	578,646	289 323	82,660	6	699,286
926	Pension & Benefits	518,468	1,227,877	2,279,233	1,139,617	43,650	1,547	2,931,158
930	General Advertising Exp	1,317,654	0	0	0	0	0	1,317,654
935	Maint General Plant	0	0	36,022	18,011	0	0	18,011
	Total O&M	24,451,862	40,930,550	89,922,054	44,961,027	23,515,368	24,610,993	158,469,761
408	Payroll Taxes	193,086 a.	397,757 b	615,725 c	307,863	11,315 d	501 e	910,501
	Other Taxes	78,937	0	0	0	0	0	78,937
	Property Taxes	836,550	1,467,230	0	0	0	454,337	2,778,117
	Total	1,108,553	1,864,987	615,725	307,863	11,315	454,838	3,767,555
411 1	Accretion Expense	0	0	0	0	0	0	0
		25,560,435	42,815,537	90,537,780	45,268,890	23,526,683	25,065,771	162,237,316

Source: 2015 TEP Lead-Lag Summary Workpapers

TUCSON ELECTRIC POWER COMPANY
Payroll Tax Expense
Test Year Ended December 31, 2011

TEP Employer Tax - 2011			
Social Security	$ 7,311,295	per Form 941	
Medicare	1,963,775	per Form 941	
FUTA/SUTA	206,758	per FUTA and SUTA returns	
	① 9,481,829	a	

	Wages, tips and other compensation from Form 941		
1Q 2011	35,453,451		
2Q 2011	27,489,066		
3Q 2011	31,254,470		
4Q 2011	31,940,018		
	126,137,006	0.075	effective tax rate (A)
Payroll Adjustment		3,471,109	(B)
Employer Payroll Tax Adjustment		$ 260,926	(A) X (B)

① 9,481,829.0 x
0.65310 =
6,192,582.5199 ÷
x

Source: TEP Payroll Tax Expense
2012 Pro Forma Adjustment

Tucson Electric Power Company
2011 FERC Form 1 Pages 354-358 Allocation Worksheet
Allocation Based on 2011 Stores Issued Activity

Note: Acct 0163 is being allocated based on the percentage of materials issued to the respective FERC accounts. See attached Query results for percentage backup for each FERC account.	%'s for Allocation of Acct 0163		Initial Clearing Acct Balances		Allocation of Acct 0163	Allocation of Acct 0184	Total Allocation Adjustment	
Total Construction 0107	7b	0.83088			2,288,197.55	3,676,070.55	5,966,268.11	m
Plant Removal 0108	7c	-0.15664			(431,333.24)	81,351.37	(349,981.88)	n
143 Other Accounts Receivable					0.00	0.00	-	
146 Intercompany AR					0.00	1,484,001.38	1,484,001.38	o
151 Fuel Stock					0.00	12,191.10	12,191.10	p
152 Coal Handling					0.00	77,247.46	77,247.46	q
163 Stores Expense			8e	2,753,676.77	(2,753,676.77)	w		
182 Other Regulatory Assets					0.00	0.00	-	
183 Preliminary Engineering	7f	0.00676			18,603.24	13,724.13	32,327.37	r
184 Clearing Accounts	7a	0.00593	8g	16,405,580.82	x	16,598.56	(15,422,179.38)	
186 Miscellaneous Deferred Debts					0.00	2,562.64	2,562.64	s
188 Research & Development					0.00	0.00	-	
416 Merchandising Expense					0.00	0.00	-	t
417 Non-Utility Income & Expense	7d	0.00507			13,983.82	15,424.26	29,387.88	u
426 Other Deductions					0.00	5,342.82	5,342.82	v
Total O&M	7e	0.30782			847,847.03	10,072,283.68	10,918,810.71	y
		1.00000		16,158,257.59	0.00	0.00	16,158,257.59	

Per P. McKee:
Allocation of Acct 0184 should be based upon relative amounts in all payroll salary and wage accounts (exclusive of 0163 and 0184).

			%'s for Allocation of Acct 0184		
O&M	1.1V	66,386,330.36	0.68319	(a)	10,072,283.68
Construction	1.1W	24,961,190.33	0.23849		3,676,070.55
Removal	1.1O	(418,360.46)	0.00386		81,351.37
143 Other Accounts Receivable		-	0.00000		0.00
146 Intercompany AR	2p	16,071,161.06	0.09823		1,484,001.38
151 Fuel Stock	2b	82,734.79	0.00079		12,191.10
152 Coal Handling	2c	524,239.12	0.00501		77,247.46
182 Other Regulatory Assets		-	0.00000		0.00
183 Preliminary Engineering	2f	93,138.65	0.00089		13,724.13
186 Miscellaneous Deferred Debts	2h	17,391.33	0.00017		2,562.64
188 Research & Development		-	0.00000		0.00
416 Merchandising Expense		-	0.00000		0.00
417 Non-Utility Income & Expense	2i	104,676.57	0.00100		15,424.26
426 Other Deductions	2j	36,256.99	0.00035		5,342.82
Total		104,662,471.84	1.00000		15,422,179.38

Reconciliation:		
Total Salaries & Wages - FERC pg.355	1.1U	131,316,296.32
Less: Incentive Compensation	-2k	(4,982,218.00)
146 Intercompany AR	-2B	(10,296,689.09)
151 Fuel Stock	-2C	(82,734.79)
152 Coal Handling	-2D	(524,239.12)
154 Materials & Operations	-2E	(568.09)
163 Stores Expense	-2F	(2,753,676.77)
183 Preliminary Engineering	-2G	(93,138.65)
184 Clearing Accounts	-2H	(15,405,580.82)
186 Misc Deferred Debts	-2I	(17,391.33)
417 Non-Utility Income & Expense	-2J	(104,676.57)
426 Other Deductions	-2k	(3,440,811.99)
	1.1P	93,732,871.13

<---Payroll by Function FBG Total Electric Payroll

8184 Acct to be Allocated:		
Direct 0184	8G	16,405,580.82
Allocated from 0163		16,598.56
		16,422,179.38

see above allocation of 0163 to 0184

Other Accounts:

FERC Account Per FERC P354 / FBG Report:		Amount	
143 Other Accounts Receivable	2A	0.00	
146 Intercompany AR	2M	5,072,832.13	a
151 Fuel Stock	2C	82,734.79	b
152 Coal Handling	2D	524,239.12	c
154 Materials and Operations	2E	568.09	d
163 Stores Expense	2F	2,753,676.77	e
182 Other Regulatory Assets		0.00	
183 Preliminary Engineering	2G	93,138.65	f
184 Clearing Accounts	2H	15,405,580.82	g
185 Temporary Facilities		0.00	
186 Miscellaneous Deferred Debts	2I	17,391.33	h
188 Research & Development		0.00	
416 Merchandising Expense		0.00	
417 Non-Utility Income & Expense	2J	104,676.57	i
426 Other Deductions	2N	36,256.99	j
	2O	24,691,697.26	k

Procedures for Allocating Payroll Charged to Clearing Accts (0182 & 0184):
1 Run a Query on Materials Issued by FERC Acct.

2. Calculate %'s for each FERC account group (relative materials issued).

3. Allocate total costs in 0163 (Stores Expense) to all other accounts (including 0184) based on these %'s.

4. Allocate 0184 costs (including allocation from 0163) into O&M, Construction, Removal and other components based on Payroll by Function FBG.

5. Total adjustments by account and post to FERC Form 1 pages 354-356.

TUCSON ELECTRIC POWER COMPANY
INCENTIVE COMPENSATION EXPENSE
AVERAGE FOR THE YEARS ENDED DECEMBER 31, 2009 TO 2011

FERC	2011	2010	2009	3 Year Avg	(A) Normalized 3 Year Average Including 1% Increase	(B) Test Year Ending Dec. 31, 2011	(A) - (B) ***Distribution of Incentive Comp Adjustment - Wage Increase	***Reclass Adjustment to Revenue Requirements	Total Adjustment
0500	127,794	273,978	296,345				11,019	44,500	55,519
0506	1,197,693	1,151,433	1,189,384				103,272	417,060	520,332
0514	471,898	593,126	569,456				40,690	164,325	205,015
0566	894,673	516,562	404,391				77,144	311,543	388,687
0570	94,452	185,560	185,521				8,144	32,889	41,033
0580	81,183	86,400	95,506				7,000	28,269	35,269
0588	327,560	363,106	370,884				28,244	114,062	142,306
0598	51,797	62,849	73,013				4,466	18,036	22,502
0903	344,814	389,938	476,601				29,732	120,072	149,804
0920	2,160,060	2,228,357	2,752,086				186,255	752,186	938,441
O&M	5,751,924	5,851,310	6,413,169	6,005,468	6,247,890	5,751,924	495,966	2,002,942	2,498,908
0408 FICA TAX*	431,394	438,848	480,988	450,410	468,592	431,394	37,198	150,220	187,418
Total	6,183,318	6,290,158	6,894,156	6,455,878	6,716,482	6,183,318	533,164	2,153,162	2,686,326

a

Pay Increase				
1% per year**				
2009	-	-	-	
2010	-	-	64,132	
2011	-	58,513	64,132	
2012	57,519	58,513	64,132	
2013	57,519	58,513	64,132	
2014	57,519	58,513	64,132	
	172,558	234,052	320,658	242,423
Taxes				
2009	-	-	-	
2010	-	-	4,810	
2011	-	4,388	4,810	
2012	4,314	4,388	4,810	
2013	4,314	4,388	4,810	
2014	4,314	4,388	4,810	
	12,942	17,554	24,049	18,182

*FICA Tax = 7.5% Effective tax rate per Payroll Tax Pro Forma
**Average wage increase of 1% for Unclassified Payroll per Payroll Adjustment Pro Forma. Only unclassified employees participate in the incentive compensation program.
***Total adjustment has been computed as the difference between the total 3-year average of 2009-2011 versus the total Incentive Compensation recorded. The adjustment has been distributed to FERC accounts based on the 12 Month Ending December 31, 2011 account distribution.

Soure: 2012 Incentive Compensation Pro Forma Adjustment

REMOTE GENERATING STATIONS
TEST YEAR ENDING DECEMBER 31, 2011

Acct	Descriptions	1 Four Corners	2 Navajo	3 San Juan	4 Luna
500	Steam Prod Oper-Supervision	276,370	793,843	2,096,137	777
501	Fuel - Steam	12,505,365	23,283,218	76,842,235	0
502	Steam Expense	1,331,184	1,156,245	1,774,754	0
505	Electric Expense	108,498	283,878	1,479,918	0
506	Steam Prod-Misc Expense	732,756	1,115,126	1,610,722	0
507	Rent	79,863	0	0	0
510	Maint-Supervision & Engr	199,711	529,543	1,422,930	0
511	Maint of Structures	87,444	143,611	1,262,184	0
512	Maint of Boiler Plant	1,998,641	3,266,357	11,027,962	0
513	Steam Prod-Mnt Elect Plant	382,249	1,560,004	1,650,458	0
514	Steam Prod-Mnt Misc Plant	749,309	447,228	1,408,941	0
546	Other Prod Oper-Supervision	0	0	0	4,158,305
547	Fuel - Other Pwr Generation	0	0	0	22,469,452
553	Maint Gen & Elec Plant	0	0	0	1,281
556	System Control and Load Dispatching	72,738	42,839	275,457	152,817
560	Operation Supervision & Engineering	1,158	0	15,161	8,296
561	Load Dispatch	0	0	109,316	60,647
562	Trans-Load Dispatch	1,891	0	48	0
568	Maintenance Supervision & Engineering	448	0	0	0
570	Maintenance of Station Equipment	39,149	0	0	0
573	Trans-Maint Supv & Engr	325		0	0
920	A&G Salaries	4,198	5,071	1,165,637	0
921	Office Supplies/Expense	1,463	1,069,488	492,407	43,109
923	Outside Services	0	0	601,902	0
924	Property Insurance	164,975	109,254	325,214	76,493
925	Injuries and Damages	18,563	51,350	580,198	48,847
926	Pension & Benefits	741,803	962,491	2,790,207	62,193
930	General Advertising Exp	591,823	0	0	0
935	Maint General Plant	0	0	38,188	0
	Total O&M	20,069,924	34,819,548	106,969,978	27,082,218
408	Payroll Taxes	153,017 a	321,439 b	694,836 c	10,621
	Other Taxes	46,168	0	0	0
	Property Taxes	836,550	439,642	0	0
	Total	1,035,735	761,081	694,836	10,621
411.1	Accretion Expense	65,575	102,071	57,988	4,088
		21,191,234	35,682,700	107,722,801	27,096,926

Source: 2012 TEP Lead-Lag Summary Workpapers

As Filed

Tucson Electric Power Company
Cash Working Capital - Lead/Lag Study
For the Test Year Ending June 30, 2015

Description	FERC	Pro Forma Test Year Amount	Ref (1)	Revenue Lag Days	Ref (2)	Expense Lag Days	Ref (2)	Net Lag Days (Col. C - Col. D)	Lead/Lag Factor (Col. E/365)	Cash Working Capital Required (Col. F X Col B)
(A)		(B)		(C)		(D)		(E)	(F)	(G)
Operating Expenses:										
Non-Cash Expenses -										$ -
Bad Debts Expense	904	$ 1,723,975	1.							-
Depreciation	403/404	156,891,230	2.							-
Amortization	Multi	2,070,108	3							-
Deferred Income Taxes	410/411	40,476,449	4.							
Other Operating Expenses -										
Salaries and Wages	Multi	71,355,623	5.	38.62	A	10.46	B	28.16	0.0772	5,508,654
Incentive Pay	Multi	8,606,720	6.	38.62	A	259.50	B	(220.88)	(0.6052)	(5,208,787)
Fuel Expense	501/547	301,256,312	7	38.62	A	28.50	C	10.12	0.0277	8,344,800
Lease Expense	507/501	15,768,836	8.	38.62	A	94.33	E	(55.71)	(0.1526)	(2,406,324)
Remote Generating Plant O&M	Multi	47,732,871	9.	38.62	A	(6.90)	F	45.52	0.1247	5,952,289
Office Supplies and Expenses	921	11,750,832	10.	38.62	A	12.46	G	26.16	0.0717	842,535
Outside Services	923	12,768,854	11.	38.62	A	44.51	G	(5.89)	(0.0161)	(205,579)
Property Insurance	924	2,517,465	12.	38.62	A	0.00	G	38.62	0.1058	266,348
Injuries and Damages	925	1,677,861	13.	38.62	A	(13.27)	G	51.89	0.1422	238,582
Pensions and Benefits	926	21,130,826	14.	38.62	A	13.03	G	25.59	0.0701	1,481,271
Miscellaneous General Expenses	930	4,700,936	15	38.62	A	(2.00)	G	40.62	0.1113	523,214
Rents	931	819,229	16.	38.62	A	(40.51)	G	79.13	0.2168	177,609
Property Taxes	408	46,931,391	17.	38.62	A	213.43	H	(174.81)	(0.4789)	(22,475,443)
Payroll Taxes	408	10,391,284	18	38.62	A	15.73	H	22.89	0.0627	651,533
Current Income Taxes	409	- (a)		38.62	A	-	H	38.62	0.1058	-
Other Taxes	408	78,937	19	38.62	A	91.38	H	(52.76)	(0.1445)	(11,406)
Interest on Customer Deposits	431	31,250	20.	38.62	A	182.50	I	(143.88)	(0.3942)	(12,319)
Other Operations and Maintenance	Multi	76,989,263	X	38.62	A	11.99	J	26.63	0.0730	5,620,216
Total Operating Expenses		$ 835,670,250								
Other Cash Working Capital Elements:										
Interest on Long-Term Debt	Calc	57,960,902		38.62	A	86.20	I	(47.58)	(0.1304)	(7,558,102)
Revenue Taxes and Assessments	Calc	94,388,041		38.62	A	48.16	H	(9.54)	(0.0261)	(2,463,528)
Total Cash Working Capital										$ (10,734,427)
Proforma Operating Expenses - Excluding Income Taxes From RR Model		$ 795,193,802								
Proforma Operating Expenses - Excluding Income Taxes and Other O&M From Above		(718,204,538.14)								
Proforma Oper. Exp. To Tie Too - Excl Income Taxes		$ 76,989,263	X							

Ref (1) = Reclassification Tab within 2011 TEP Lead-Lag Summary Excel Workbook
Ref (2) = 2011 TEP Lead Lad Study back-up within a Binder by Tabs

TUCSON ELECTRIC POWER COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2015

Expense

ADJUSTMENT NAME:	Payroll Adjustment
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	October 5, 2015
PREPARED BY:	Carisa Williams
CHECKED BY:	Anne Liu
REVIEWED BY:	Brian Brumfield 10/30/15

FERC ACCT	FERC ACCOUNT DESCRIPTION	Total Company DEBIT	Total Company CREDIT	ACC Jurisdictional DEBIT	ACC Jurisdictional CREDIT
		F-3a-1			
0500	Steam Prod Oper-Supervision	$309,352		$277,745	
0501	Fuel - Steam	26,739		26,739	
0502	Steam Expenses	366,469		329,026	
0505	Electric Expenses	121,744		109,305	
0506	Steam Prod-Misc Expense	90,179		80,965	
0546	Other Prod Oper-Supervision	1,945		1,746	
0549	Misc Other Pw Gen Exp	5		4	
0556	Sys Cntrol/Load Dispatch	50,486		0	
0557	Prod Expense-Other	12,006		10,779	
0560	Trans-Oper Supv & Engr	55,961		0	
0580	Dist-Oper Supv & Engr	20,456		20,456	
0581	Dist-Load Dispatching	21,099		21,099	
0582	Dist-Station Expenses	8,121		8,121	
0583	Dist-Overhead Line Exp	18,937		18,937	
0584	Dist-Underground Line Exp	8,782		8,782	
0585	Dist-Light/Signal Exp	4		4	
0586	Dist-Meter Expenses	32,033		32,033	
0587	Dist-Customer Install Exp	2,131		2,131	
0588	Dist-Misc Expense	147,935		147,935	
0902	Meter Reading Expense	21		21	
0903	Cust Rec/Collection Exp	282,667		282,667	
0908	Customer Assistance Exp	2,791		2,791	
0909	Informational/Instrct Adv Exp	295		295	
0920	A&G Salaries	978,801		821,290	
0923	Outside Services	2,919		2,449	
0925	Injuries & Damages	3,174		2,663	
0926	Pensions & Benefits	59,689		50,084	
0930	General Advertising Exp	8,017		6,727	
5611	Load Dispatch-Reliability	32,047		0	
5612	Load Dispatch-Monitor and Operation Transmiss	37,690		0	
5613	Load Dispatch-Transmission Service and Schedu	27,225		0	
	ENTRY TOTAL	**$2,729,720**	**$0**	**$2,264,794**	**$0**
	NET ENTRY	**$2,729,720**		**$2,264,794**	

Reason for Adjustment

To adjust payroll expense recorded in the test year by applying a known average wage rate increase of 2% to average TEP wages (exclusive of wages for external ownership % of SGS Unit 1 and all of SGS Units 3 and 4, and increases in executive wages post Fortis merger).

TUCSON ELECTRIC POWER COMPANY
Payroll Adjustment
Test Year Ended June 30, 2015

	Wages Charged to O&M			Exclude A&G Payroll			
	Total Payroll	Clearing Account Allocations to O&M	Deduct SGS Unit 1 - External owners	Capitalized through A&G Loader	Deduct SGS Unit 3 Wages	Deduct SGS Unit 4 Wages	Total O&M Wages
Jun-14	74,298,455 5.1a	15,808,352 6.1a	(3,385,007) 7.1a	(5,289,752) 5.2a	(7,789,279) 8a	(7,134,089) 9a	66,508,680
Jun-15	76,779,720 + b	17,193,144 6a	(3,365,954) 7.1b	(6,234,866) + b	(7,227,233) + b	(8,518,905) + b	68,625,903
	151,078,174	33,001,496	(6,750,962)	(11,524,619)	(15,016,512)	(15,652,994)	135,134,583

2 Year Average O&M Wages		67,567,291
Average Wage Rate Increase	2016	2% 9c
		1,351,346
		68,918,637
Average Wage Rate Increase	2017	2% 9c
		1,378,373
Total Payroll Adjustment		2,729,720 a

TEP(0322)003144

9

10/14/2015 1:06 PM

Docket No. E-01933A-15-0322
Attachment DHM-17
Page 2 of 3

TUCSON ELECTRIC POWER COMPANY
PAYROLL ADJUSTMENT
SUMMARIZED BY FERC ACCOUNT - PRO FORMA INPUT

Row Labels	Description	Sum of Adjustment
0500	Steam Prod Oper-Supervision	309,352
0501	Fuel - Steam	26,739
0502	Steam Expenses	366,469
0505	Electric Expenses	121,744
0506	Steam Prod-Misc Expense	90,179
0546	Other Prod Oper-Supervision	1,945
0549	Misc Other Pw Gen Exp	5
0556	Sys Cntrol/Load Dispatch	50,486
0557	Prod Expense-Other	12,006
0560	Trans-Oper Supv & Engr	55,961
0580	Dist-Oper Supv & Engr	20,456
0581	Dist-Load Dispatching	21,099
0582	Dist-Station Expenses	8,121
0583	Dist-Overhead Line Exp	18,937
0584	Dist-Underground Line Exp	8,782
0585	Dist-Light/Signal Exp	4
0586	Dist-Meter Expenses	32,033
0587	Dist-Customer Install Exp	2,131
0588	Dist-Misc Expense	147,935
0902	Meter Reading Expense	21
0903	Cust Rec/Collection Exp	282,667
0908	Customer Assistance Exp	2,791
0909	Informational/Instrct Adv Exp	295
0920	A&G Salaries	978,803
0923	Outside Services	2,919
0925	Injuries & Damages	3,174
0926	Pensions & Benefits	59,689
0930	General Advertising Exp	8,017
5611	Load Dispatch-Reliability	32,047
5612	Load Dispatch-Monitor and Operation Transmiss	37,690
5613	Load Dispatch-Transmission Service and Schedu	27,225
Grand Total		2,729,720

TUCSON ELECTRIC POWER COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2015

ADJUSTMENT NAME:	Income - Payroll Tax Expense
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	October 2, 2015
PREPARED BY:	Carisa Williams
CHECKED BY:	Anne Liu
REVIEWED BY:	Brian Brumfield 10/30/15

		Total Company		ACC Jurisdictional	
FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT	DEBIT	CREDIT
408	Taxes Other Than Income Taxes	$180,020		$151,051	
	ENTRY TOTAL	$180,020	$0	$151,051	$0
	NET ENTRY	$180,020		$151,051	

Reason for Adjustment

To adjust payroll tax expense recorded in the test year based on an annualized normal payroll level times the 2014 / 2015 effective employer payroll tax rate.

TUCSON ELECTRIC POWER COMPANY
Payroll Tax Expense
Test Year Ended June 30, 2015

TEP Employer Tax - Ended June 2015

Social Security	7,900,994	per Form 941
Medicare	2,450,273	per Form 941
FUTA/SUTA	143,232	per FUTA and SUTA returns
	10,494,500	

	Wages, tips and other compensation from Form 941
Q3 2014	62,328,958
Q4 2014	35,209,774
Q1 2015	27,716,883
Q2 2015	33,876,917
	159,132,532

0.066 effective tax rate (A)

Payroll Adjustment — 2,729,720 (B) (from Payroll Expense Adj)

Employer Payroll Tax Adjustment — $ 180,020 (A) X (B)

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 21, 2016

STF 7.08

Payroll Expense:

Reference UDR 1.003, prospectus for long-term debt, page 42. The prospectus stats that the IBEW Local No. 1116 collective bargaining agreement was entered in January 2013 and expires in January 2016. Has a new collective bargaining agreement been negotiated and approved by the union? If so, please provide a copy. If not, please explain the status of the negotiations.

RESPONSE:

The executed agreements have not met final approval by the IBEW Local 1116 or the IBEW International office.

RESPONDENT:

Tina Harris

WITNESS:

Frank Marino

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 21, 2016

STF 7.04

Payroll Expense:

Reference Direct Testimony of Frank Marino, page 31, lines 20-21 and workpaper Income-Payroll Expense page 2. Please provide the basis used to estimate the wage increase for 2017 of 2%.

RESPONSE:

The 2017 wage increase estimate of 2% was based on the average classified and unclassified wage increase for 2015 and is consistent with the 2014 and approved 2016 wage increases.

RESPONDENT:

Georgia Hale

WITNESS:

Frank Marino

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 14, 2016

RUCO 5.2

Long-Term Incentive Compensation – Please answer the following questions as they relate to long-term incentive compensation:

a. To clarify the Company is seeking long-term incentive compensation of $1,349,782 in the test year and $1,049,924 as a pro forma adjustment for a total of $2,399,706 in long-term incentive expense in this case. If no please explain.

b. Why did the Company not request long-term incentive compensation in its last rate case?

c. Has the Company in prior rate cases asked for long-term incentive compensation? If so, please provide the docket number, along with the Commission decision relating to the Company's request.

d. Why is the Company using a two year average as opposed to a three year average?

e. What Company executives or officers are eligible for the program?

f. List the names of the executives or officers in d. above along with the total long-term incentive compensation provided to them by fiscal year for the test year and three prior years. The test year and prior year amount should reconcile to your pro forma adjustment.

g. Provide a sub account that breaks-out the long-term compensation amounts between salary and payroll taxes for the years noted in f., the test year and prior year amount should reconcile to your pro forma adjustment.

h. From the Company's pro-forma adjustment $180,098 has been capitalized. Please explain to what accounts this amount was allocated to and how this amount was allocated

i. Was any long-term incentive compensation between 7/1/14 through 12/31/14 capitalized? If so, please provide the amount and explain to what accounts this amount was allocated to and how this amount was allocated.

j. Please explain the Fortis Merger long-term incentive compensation expense offset to the Company's pro-forma adjustment in the amount of $2,534,690, and how it was calculated.

k. Please provide a copy of any and all long-term incentive compensation program document(s), and explain how the performance units and restricted stock units relate to the performance goals, if not already provided.

l. Please provide a copy of the Company's benchmarking study.

m. What is the capitalization percentage for the test year?

RESPONSE: **April 4, 2016**

a. No. While responding to data request AECC 5.1, the Company discovered that the amount listed as Fortis Merger LTI Compensation expense was incorrect. As a result the Pro Forma adjustment was updated accordingly. The Company is seeking long-term incentive

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 14, 2016

compensation of $491,910 in the test year and $1,191,919 as a pro forma adjustment for a total of $1,683,829 in long-term incentive expense in this case

b. Because of the size of the revenue request in the last rate case, the Company decided to not request long-term incentive compensation in this last rate case, but reserved the right to request it in this case.

c. Not in the last two rate cases.

d. The Company used the same two year methodology as it did for the payroll adjustment.

e./f. TEP is in the process of gathering this information and will provide it as soon as possible.

g. The Long-Term Incentive Compensation Pro Forma Adjustment does not include payroll taxes.

h. The $180,098 capitalized amount was allocated to FERC 107 via the A&G Allocation.

i. No long-term incentive compensation between 7/1/14 through 12/31/14 was capitalized.

j. The Fortis Merger triggered the payout of all outstanding long-term incentive awards resulting in the accelerated recognition of compensation expense. Compensation expense on these annual awards is typically recognized ratably over a three-year term. In order to normalize the pro forma adjustment, the amount related to the accelerated recognition of compensation expense as a result of the Fortis Merger was deducted. This amount was calculated as follows:

Total Estimated Additional Comp Expense in 2014	$2,680,890
Multiplied by: TEP Mass. Allocation Percentage	x 80.46%
	2,157,044
Add: Payroll Taxes on LTI Payouts	377,646
	$2,534,690

The Payroll Taxes on LTI Payouts amount listed above should not have been included in the Long-Term Incentive Compensation Pro Forma Adjustment. The pro forma adjustment was subsequently updated in a recent data request as referred to in RUCO 5.2a above.

k. Please see the following attached files:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

File Name	Bates Numbers
RUCO 5.2k - 2012 LTI Term Sheet-Confidential.pdf	TEP\021453-021455
RUCO 5.2k - 2013 LTI Term Sheet-Confidential.pdf	TEP\021456-021459
RUCO 5.2k - 2014 LTI Term Sheet-Confidential.pdf	TEP\021460-021463
RUCO 5.2k - 2015 LTI Term Sheet-Confidential.pdf	TEP\021464-021467

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 14, 2016

l. TEP is in the process of gathering this information and will provide it as soon as possible.

m. The capitalization percentage used in the Long-Term Incentive Compensation Pro Forma Adjustment for the test year was 24.8% for the period 7/1/14 through 12/31/14 and 26.8% for the period 1/1/15 through 6/30/15.

RESPONDENT:

Georgia Hale/ David Lewis/ Steve Bracamonte

WITNESS:

Frank Marino

SUPPLEMENTAL RESPONSE: **April 14, 2016**

THE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

e-f, l. Please see RUCO 5.2 (e f & l)-Confidential.pdf, Bates Nos. TEP\021565-021566, for the confidential responses to subparts e, f, and l.

RESPONDENT:

Georgia Hale (e. and f.) / Gabrielle Camacho (l)

WITNESS:

Frank Marino

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO AECC SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 4, 2016

AECC 7.3

Please refer to TEP's response to AECC Data Request 5.1(b).

a. Please confirm that the acquisition by Fortis occurred on 8/15/14, rather than 8/14/15 as indicated in TEP's response.

b. Please provide the workpapers in Excel format that calculate the Fortis Merger LTI Compensation Expense, for both the original Fortis Merger LTI Compensation Expense ($2,534,690) and the 3/18/16 revised Fortis Merger LTI Compensation Expense ($2,157,044). If applicable, indicate the amount of the Fortis Merger LTI Compensation Expense corresponding to each award year.

c. Please confirm that the ACC Jurisdictional Debit Amount of $0 presented on the Rev-Exp tab of TEP's Income - Long Term Incentive Compensation-Revised file is incorrect.

RESPONSE:

a. Yes, the acquisition by Fortis occurred on 8/15/14.

b. See AECC 7.3 Estimated TEP Fortis Merger LTI Compensation Expense.xlsx.

c. Yes, the ACC Jurisdictional Debit Amount of $0 presented on the Rev-Exp tab of TEP's Income – Long Term Incentive Compensation-Revised file is incorrect. The amount should have been $1,000,112.

RESPONDENT:

Ann Eckert

WITNESS:

Frank Marino

Tucson Electric Power Company
2014 Estimated Additional LTI Compensation Expense Due to Change in Control Trigger (Fortis Acquisition)

2014 Board of Directors Restricted Stock Units Award:		
Monthly Regular Comp Exp x 5	$	150,863
Aug-14 J902 Actual Comp Exp		271,553
Add'l Comp Exp	$	120,690
2013 Restricted Stock Units Award:		
Monthly Regular Comp Exp x 5	$	96,763
Aug-14 J902 Actual Comp Exp		367,699
Add'l Comp Exp	$	270,936
2014 Restricted Stock Units Award:		
Monthly Regular Comp Exp x 5	$	114,119
Aug-14 J902 Actual Comp Exp		707,535
Add'l Comp Exp	$	593,416
2012 TSR Performance Share Award:		
Monthly Regular Comp Exp x 5	$	123,305
Aug-14 J902 Actual Comp Exp		123,305
Add'l Comp Exp	$	-
2013 TSR Performance Share Award:		
Monthly Regular Comp Exp x 5	$	95,312
Aug-14 J902 Actual Comp Exp		324,059
Add'l Comp Exp	$	228,748
2014 TSR Performance Share Award:		
Monthly Regular Comp Exp x 5	$	108,607
Aug-14 J902 Actual Comp Exp		629,918
Add'l Comp Exp	$	521,312

2012 CNI Performance Share Award (@145.4% Attainment Level*):		
Monthly Regular Comp Exp (*) x 5	$	199,497
Aug-14 J902 Actual Comp Exp		(294,321)
Add'l Comp Exp	$	(493,818)
2013 CNI Performance Share Award (@115.8% Attainment Level*):		
Monthly Regular Comp Exp (*) x 5	$	112,053
Aug-14 J902 Actual Comp Exp		491,297
Add'l Comp Exp	$	379,244
2014 CNI Performance Share Award (@104.1% Attainment Level*):		
Monthly Regular Comp Exp (*) x 5	$	118,807
Aug-14 J902 Actual Comp Exp		655,323
Add'l Comp Exp	$	536,516

Summary:		
Total Estimated Additional Comp Expense in 2014	**$**	**2,157,044**
Add: Payroll Taxes on LTI Payouts		**377,646**
	$	**2,534,690**

* LTI compensation expense regular monthly accrual for the CNI Performance Share Awards based on actuals to date (Jun-14) plus forecast (ActJun14) over the remaining performance period; however, payout due to change in control trigger as a result of the Fortis Acquisition done at Target.

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO UNIFORM DATA REQUESTS - 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
November 13, 2015

UDR 1.035

Payroll, Incentive Programs.

a. Please provide complete copies of any bonus programs or incentive award programs in effect at the Company for the most recent three years.

b. Identify all incentive and bonus program expense incurred in 2012-2014. Identify the accounts charged.

c. Identify all incentive and bonus program expense charged or allocated to the Company from affiliates in 2012-2014.

RESPONSE:

a. **ONE OF THE FILES LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.**

Please see TEP's response to UDR 1.034 for the description of the short term incentive program available to TEP's non-union employees related to their annual compensation. Union employees are not eligible for PEP.

Long-term Incentive Program ("LTI"):

As set forth in the direct testimony of Frank Marino, officers of UNS who provide services to TEP are eligible to participate in a long-term incentive compensation program. Please see UDR 1.035 2014 LTI Term Sheet-Confidential.pdf, Bates Nos. TEP\015530-015533 for the description of the program.

b.-c. Please see UDR 1.035 TEP Incentive Comp and Bonus Summary Info.xls for both short-term and long-term incentive program expense directly charged or allocated to TEP in 2012 through 2014 and the corresponding accounts charged. The Excel file is not identified by Bates number.

RESPONDENT:

Gabrielle Camacho (a) and Pauline Rush (b and c)

WITNESS:

Frank Marino

Tucson Electric Power Company
Test Year Ended 6/30/15
Support for UDR 1.035 Item (b)and (c)

CONFIDENTIAL

Incentive Compensation (PEP) Program Expense

FERC		2012	2013	2014
0426	(1)	3,052,497	3,431,137	3,756,634
0500		54,615	78,527	90,391
0506		812,359	904,093	1,012,675
0514		302,851	318,642	393,204
0566		566,146	593,912	722,736
0570		73,541	58,854	59,887
0580		51,783	4,025	830
0588		201,991	205,036	236,034
0598		37,107	51,898	60,744
0903		186,660	202,871	144,012
0920		1,428,965	1,786,091	2,286,429
		6,768,515	7,635,086	8,763,576

Long Term Incentive (LTI) Compensation Program Expense

FERC		2012	2013	2014	
0426	(2)	1,595,422	2,332,075	4,531,551	(3)

Spot Awards Compensation Program Expense

FERC	2012	2013	2014
0500	-	9,500	7,734
0506	-	-	10,000
0560	-	7,210	-
0580	-	-	11,847
0920	175,665	950,731	634,832
	175,665	967,441	664,413

(1) 2012-2014 PEP Expense allocated a portion of expense to FERC 426; beginning in 2015 we are no longer allocating any expense to FERC 426 (allocating to various O&M FERCs instead). The portion now being allocated to FERC 920 would result in capitalized A&G.

(2) 2012-2014 LTI Expense was charged to FERC 426; beginning in 2015 we are now charging LTI Expense to FERC 920 which would result in capitalized A&G.

(3) 2014 LTI Expense includes $2,534,690 related to the Fortis Merger. This amount was excluded from the test year in the LTI Proforma Adjustment.

/Users/tracymullinax/ownCloud/Projects/Arizona TEP/DMS/Responses/UDR/UDR 1.035 TEP Incentive Comp and Bonus Summary Info.xls

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TEP TY 06-30-15
UDR 1.035 Payroll, Incentive Programs
Summary - Response to b and c

TOTAL:

	2012	2013	2014	
PEP	$ 6,768,515.44	$ 7,635,086.47	$ 8,763,575.63	
LTI	1,595,422.27	2,332,074.69	4,531,551.46	(1)
Spot Awards	175,665.00	967,440.67	664,412.83	
Total	**$ 8,539,602.71**	**$ 10,934,601.83**	**$ 13,959,539.92**	

(1) 2014 LTI Expense includes $2,534,690 related to the Fortis Merger. This amount was excluded from the test year in the LTI Proforma Adjustment.

/Users/tracymullinax/ownCloud/Projects/Arizona TEP/DMS/Responses/UDR/UDR 1.035 TEP Incentive Comp and Bonus Summary Info.xls

CONFIDENTIAL

THE FOLLOWING DOCUMENT CONTAINS "CONFIDENTIAL INFORMATION" THAT IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT IN THIS DOCKET AND MAY NOT BE SHARED WITH ANYONE WHO HAS NOT SIGNED THE PROTECTIVE AGREEMENT.

DONNA H. MULLINAX

SCHEDULE DHM-23

PAGES 5-7

REDACTED

TUCSON ELECTRIC POWER COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2015

ADJUSTMENT NAME:	Short-Term Incentive Compensation
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	August 21, 2015
PREPARED BY:	Paige Bennetts
CHECKED BY:	Rigo Ramirez
REVIEWED BY:	David Lewis

		Total Company		ACC Jurisdictional	
FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT	DEBIT	CREDIT
0408	Taxes Other Than Inc Tax	39,006.03		$32,729	
0500	Steam Prod Oper Supervision	44,383.63		$39,849	
0506	Steam Prod Misc Expense	477,839.77		$429,018	
0514	Steam Prod Mnt Elec Plnt	169,385.23		$152,079	
0566	Trans Misc Oper Expense	395,542.66		$0	
0570	Trans Maint Stn Equip	39,056.22		$0	
0580	Dist Oper Supv & Engr	2,298.48		$2,298	
0588	Dist Misc Expense	74,523.51		$74,524	
0598	Dist Maint Misc Plant	19,546.36		$19,546	
0903	Cust Rec/Collection Exp	97,347.99		$97,347	
0920	A&G Salaries		172,128.91		$144,430
	ENTRY TOTAL	$1,358,929	$172,129	$847,390	$144,430
	NET ENTRY	$1,186,800		$702,960	

Reason for Adjustment
Incentive compensation expense is calculated by applying a wage increase of 2% for unclassified payroll to the average incentive compensation expense for the 12-month periods ended June 14 and June 2015. Only unclassified employees participate in the incentive compensation program.

The adjustment includes related payroll taxes.

TUCSON ELECTRIC POWER CO.
INCENTIVE COMPENSATION EXPENSE
7/1/2013-6/30/14, 7/1/14-6/30/15 Pro Forma Adjustments

		7/1/13-6/30/14		7/1/14-6/30/15	2 Yr Average		7/1/14-6/30/15 Test Year	Difference
0408	4a	569,673.18	4b	562,726.88	566,200.03	14.1A	527,194.00	39,006.03
0500	3.1A	160,748.25	3b	146,843.01	153,795.63	5A	109,412.00	44,383.63
0506		1,833,265.09		1,688,920.45	1,761,092.77		1,283,253.00	477,839.77
0514		679,930.32		656,358.14	668,144.23		498,759.00	169,385.23
0566		1,256,695.43		1,037,909.89	1,147,302.66		751,760.00	395,542.66
0570		113,929.71		82,432.73	98,181.22		59,125.00	39,056.22
0580		4,596.96		-	2,298.48		-	2,298.48
0588		421,830.09		467,596.93	444,713.51		370,190.00	74,523.51
0598		107,572.88		118,477.83	113,025.36		93,479.00	19,546.36
0903		334,229.92		255,834.86	295,032.39		197,685.00	97,347.39
0920		3,881,601.69		3,964,666.49	3,923,134.09		4,095,263.00	(172,128.91)
		9,364,073.53		8,981,767.21	9,172,920.37		7,986,120.00	1,186,800.37
check nontax	3.1B	8,794,400.35	3B	8,419,040.33	8,606,720.34			
nonofficers	3.1C	7,334,422.07	3.1D	7,168,566.62	7,251,494.35			
0.0765 FICA		561,083.29		548,395.35	554,739.32			
check tax		8,589.89		14,331.53	11,460.71	pass		

TEP\(0322)\003422

2 G:\RATES\Rate Case 2015 TEP\Pro Forma Adjustments\Filed\Income - Short Term Incentive Compensation.xlsm, ProForma Adjust

TUCSON ELECTRIC POWER CO.
INCENTIVE COMPENSATION EXPENSE
2013, 2014, 7/1/14-6/30/15 Adjustments

Query Pivot Table by FERC: W/P 13

Row Labels	Sum of Amount SUM	Adjust J903 Mar-14 reclass officers to E&G	Adjust J028A Feb-14 2013 true up	Adjust J028A Mar-13 2012 true up	Subtotal	Adjust FERC 0920 for portion capitalized	Subtotal	Adjust FERC 0426 to other FERCs	Subtotal	Adjust Wage Increase 2% through 2017 2.00%	Total	Half Year
Cell Sum	21,704,565.61					9a 23.67% (1)	4,260,840.43 (9)	-	7,737,208.43	4 (12)	8,356,186.16	4,178,093.09
(blank)	21,704,565.61											
1/1/2013	8,360,028.00											
0426	3,602,210.00	6b (171,073.00)	7a 24,422.00	8a 20,810.00	3,476,369.00		3,476,369.00 (10)	(3,476,369.00)	-	(11) X 11,636.36	-	-
0500	76,527.00		7.1b 1,751.00	8.1b (177.00)	80,101.00		80,101.00 (7)	(7)+(8) 65,353.45	145,454.45 (13)	(12) X 133,170.99	157,090.81	÷ 2 = 78,545.40
0506	904,093.00		7c 5,146.00	8c 7,468.00	916,707.00		916,707.00	747,930.33	1,664,637.33	(13) 46,957.70	1,797,806.32	898,904.16
0514	316,842.00		7d 1,815.00	8d 2,785.00	323,242.00		323,242.00	x(10) 283,729.30	566,971.30		633,929.01	316,964.50
0566	593,912.00		7e 4,240.00	8e 3,818.00	602,070.00		602,070.00	491,221.75	1,093,291.75	87,463.34	1,180,755.09	590,377.54
0570	58,854.00		7f 336.00	8f 576.00	59,866.00		59,866.00	48,843.96	108,709.96	8,696.80	117,406.75	58,703.38
0580	4,025.00		7g 830.00	8g (167.00)	4,688.00		4,688.00	3,824.88	8,512.88	681.03	9,193.91	4,596.96
0588	205,036.00		7h 1,168.00	8h 1,857.00	208,061.00		208,061.00	169,754.49	377,815.49	30,225.24	408,040.73	204,020.37
0598	51,898.00		7i 295.00	8i 341.00	52,534.00		52,534.00	42,861.87	95,395.87	7,631.87	103,027.83	51,513.77
0903	202,871.00		7j 1,155.00	8j 1,717.00	205,743.00		205,743.00	167,863.27	373,606.27	29,886.50	403,494.77	201,747.38
0920	2,339,980.00		7k 16,494.61	8k 11,983.00	2,368,437.61	9b (560,609.18)	1,807,828.43	1,474,985.70	3,282,814.13	262,625.13	3,545,439.26	1,772,719.63
1/1/2014	9,034,755.61					24.89% (6)	4,977,891.89	-	8,710,013.89	3	9,232,814.61	4,616,307.25
0426	3,273,779.00	6a 482,855.00	(24,422.00)		3,732,212.00		3,732,212.00 (1)	(3,732,212.00)	-		-	-
0500	90,391.00		(1,751.00)		88,640.00		88,640.00	68,459.71	155,099.71	9,305.98	164,405.70	÷ 2 = 82,202.85
0506	1,012,675.00		(5,146.00)		1,007,529.00		1,007,529.00	755,416.16	1,762,945.16	105,776.71	1,868,721.87	934,360.93
0514	393,204.00		(1,815.00)		391,389.00		391,389.00	293,452.17	684,841.17	41,090.47	725,931.64	362,965.82
0566	722,736.00		(4,240.00)		718,496.00		718,496.00	538,707.56	1,257,203.56	75,432.21	1,332,635.77	666,317.89
0570	59,887.00		(336.00)		59,551.00		59,551.00	44,649.62	104,200.62	6,252.04	110,452.66	55,226.33
0580	830.00		(830.00)		-		-	-	-	-	-	
0588	236,034.00		(1,168.00)		234,866.00		234,866.00	176,095.75	410,961.75	24,657.70	435,619.45	217,809.73
0598	60,744.00		(295.00)		60,449.00		60,449.00	45,322.92	105,771.92	6,346.31	112,118.23	56,059.11
0903	144,012.00		(1,155.00)		142,857.00		142,857.00	107,110.05	249,967.05	14,998.02	264,965.08	132,482.54
0920	3,040,463.61		(16,494.61)		3,023,969.00	(749,944.31) (4)	2,274,024.69	1,704,998.06	3,979,022.75	238,741.36	4,217,764.11	2,108,882.06
1/1/2015	4,309,782.00					9c 26.89%	3,858,474.11			2	3,882,733.08	3,882,733.08
0426	-				-		-		-		-	-
0500	62,154.00				62,154.00		62,154.00		62,154.00	2,486.16	64,640.16	64,640.16
0506	725,538.00				725,538.00		725,538.00		725,538.00	29,021.52	754,559.52	754,559.52
0514	282,108.00				282,108.00		282,108.00		282,108.00	11,284.32	293,392.32	293,392.32
0566	357,300.00				357,300.00		357,300.00		357,300.00	14,292.00	371,592.00	371,592.00
0570	26,160.00				26,160.00		26,160.00		26,160.00	1,046.40	27,206.40	27,206.40
0588	240,180.00				240,180.00		240,180.00		240,180.00	9,607.20	249,787.20	249,787.20
0598	60,018.00				60,018.00		60,018.00		60,018.00	2,400.72	62,418.72	62,418.72
0903	118,608.00				118,608.00		118,608.00		118,608.00	4,744.32	123,352.32	123,352.32
0920	2,437,716.00				2,437,716.00 (8)	(653,307.89) (5)	1,784,408.11		1,784,408.11	71,376.32	1,855,784.44	1,855,784.44
Grand Total	43,409,131.22											

TEP (6/1/14-6/30/15)

(8+9c)/2 = 25.89% (3)

0426	1,419,040.33 (6)	B
0500	-	
0506	146,843.01	A
0514	1,688,920.45	
0566	856,358.14	
0570	1,037,909.89	
0580	82,432.73	
0588	-	
0598	467,598.93	
0903	118,477.83	
0920	259,834.86	
	3,964,666.49	

(0÷2 +(2))×3 (1,019,022.73)
(4)÷2 +(5) (1,028,280.04)
diff 9,257.31 pass

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Docket No. E-01933A-15-0322
Attachment DHM-24
Page 3 of 3
1/2

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO UNIFORM DATA REQUESTS - 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
November 13, 2015

UDR 1.034

Incentive Programs. List and describe all retirement and incentive programs available to Company officers and employees. Provide a complete copy of each incentive compensation program and all related materials. Identify the goals and targets in each year 2012-2014, and all evaluations of whether such goals were exceeded. State the cost by program, of each retirement program directly charged or allocated.

RESPONSE:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

Incentives:

All TEP non-union employees participate in UNS's short-term incentive program ("PEP"), which is tied to annual compensation.

The PEP performance targets and weighting are based on factors that are essential for the long-term success of the Company and are identical to the performance objectives used in its performance plan for other non-union employees. In 2015, the objectives were (i) net income; (ii) managing Long-term O&M; and (iii) excellent operations and safe work environment, which include both quantitative and qualitative measures. The Compensation Committee selected the goals and individual weightings for the 2015 PEP to ensure an appropriate focus on profitable growth and expense control, as well as operational and customer service excellence, and process improvements. This balanced scorecard approach encourages all employees to work toward common goals that are in the interests of UNS's various stakeholders. The outcomes of which all benefit our customers in the long run.

The financial and other metrics for the Company's 2015 Short-Term Incentive Compensation program were:

- Financial – 60%
  - Net Income – 40%
  - Managing Long-term O&M – 20%
- Excellent Operations and Safe Work Environment – 40%

In developing the PEP performance targets, Company management compiles relevant data such as Company historic performance and industry benchmarks and makes recommendations to the Compensation Committee for a particular year, but the Compensation Committee ultimately determines the performance objectives that are adopted.

The scores from each goal are totaled and then multiplied by the targeted bonus of each employee to determine the total available dollars to be paid out. Targeted bonus percentages, as a percent of base salary, range from 9% - 12% for unclassified employees, and 20-25% for senior management level employees. Bonus percentages, as a percent of base salary, are used in the calculation of total available dollars, and actual awards may vary at management's discretion based on individual employee contribution. If a payout is achieved, employee PEP bonuses will be distributed near the end of the first quarter the following year. Please see the files listed below for the goals for

Arizona Corporation Commission ("Commission")
Fortis Inc. ("Fortis")
Tucson Electric Power Company ("TEP")
UNS Energy Corporation ("UNS")
UNS Energy Corporation and Fortis Inc. Joint Notice of Reorganization Settlement Agreement approved in Decision No. 74689 (August 12, 2014) (the "UNS-Fortis Settlement Agreement")
UniSource Energy Services ("UES")
UniSource Energy Development Company ("UED")
UNS Electric, Inc. ("UNS Electric" or the "Company")
UNS Gas, Inc. ("UNS Gas")
UNS Electric, Inc. 2014 Rate Case Settlement Agreement approved in Decision No. 74689 (August 12, 2014) (the "2014 Settlement Agreement")

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO UNIFORM DATA REQUESTS - 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
November 13, 2015

each year and evaluations of yearly performance.

File Name	Bates Numbers
UDR 1.034 2012-2014 PEP Hist Prcnts-Pos-Confidential.pdf	TEP\015464-015465
UDR 1.034 2012 PEP Goals-Confidential.pdf	TEP\015462-015463
UDR 1.034 2013 PEP Goals-Confidential.pdf	TEP\015466-015467
UDR 1.034 2014 PEP Goals-Confidential.pdf	TEP\015468-015469
UDR 1.034 2015 PEP Goals-Confidential.pdf	TEP\015470-015471

Retirement Programs:

TEP employees are eligible to participate in one of the pension plans for employees of TEP. Please see the file listed below for the summary plan description.

File Name	Bates Numbers
UDR 1.034 TEP_Hourly_Plan_SPD-CONFIDENTIAL.pdf	TEP\015472-015500
UDR 1.034 TEP_Salary_Plan_SPD-CONFIDENTIAL.pdf	TEP\015501-015529

Additionally, TEP employees are eligible to participate in the TEP 401(k) Plan as described below:

401(k) Plan

All employees participate in the TEP's 401(k) Plan, which takes advantage of Section 401(k) of the Internal Revenue Code and permits employees to voluntarily save from 1/2% to 25% of their pay, before any deduction for state or federal income taxes. The Company matches dollar on dollar, up to 4.5% of pay saved in the 401(k) Plan for TEP employees.

Employees' savings and Company matching contributions are invested in one or any combination of a selection of professionally managed investment funds at the direction of the employee. Employees are eligible to join the 401(k) Plan upon their date of employment. Company matching contributions are fully and immediately vested. Please see the file listed below for the summary plan description.

File Name	Bates Numbers
UDR 1.034 401K_SPD-CONFIDENTIAL.pdf	TEP\015403-015461

Retirement program expense directly charged or allocated to TEP during each year was as follows:

	2012	2013	2014
TEP SERP Plan (FERC 0426)	$1,004,706	$1,115,118	$954,665
TEP Union and Salaried Pension Plans (FERC 0926)	7,334,904	7,632,836	4,206,860
TEP 401K Plan (FERC 0926)	2,828,818	2,980,758	3,062,120
UNS Electric Pension/401K (FERC 0926)	36,912	44,933	30,874
UNS Gas Pension/401K (FERC 0926)	19,070	21,384	17,007
Deferred Compensation Plan (FERC 0920)	(160,601)	(294,873)	(75,744)

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO UNIFORM DATA REQUESTS - 2015 TEP RATE CASE DOCKET NO. E-01933A-15-0322 November 13, 2015

Total	$11,063,809	$11,500,156	$8,195,782

RESPONDENT:

Steve Bracamonte

WITNESS:

Frank Marino

Arizona Corporation Commission ("Commission")
Fortis Inc. ("Fortis")
Tucson Electric Power Company ("TEP")
UNS Energy Corporation ("UNS")
UNS Energy Corporation and Fortis Inc. Joint Notice of Reorganization Settlement Agreement approved in Decision No. 74689 (August 12, 2014) (the "UNS-Fortis Settlement Agreement")

UniSource Energy Services ("UES")
UniSource Energy Development Company ("UED")
UNS Electric, Inc. ("UNS Electric" or the "Company")
UNS Gas, Inc. ("UNS Gas")
UNS Electric, Inc. 2014 Rate Case Settlement Agreement approved in Decision No. 74689 (August 12, 2014) (the "2014 Settlement Agreement")

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 12, 2016

STF 11.14

Short Term Incentive Comp: Follow up to UDR 1.001 Income-Short Term Incentive Compensation: On page 2, other than the 2% increase through 2017, there appears to be other differences in the in amounts in the column labeled 7/1/14-6/30/15 used in calculating the two-year average and the amounts in the column labeled 7/1/14-6/30/15 Test Year.

a. Please explain those differences and explain why the 7/1/14-6/30/15 should be adjusted prior to calculating the two-year average.

b. Please explain why those same adjustments should not also be made to the test year amount.

RESPONSE:

a. The column labeled "7/1/14-6/30/15 Test Year" is the actual Short Term Incentive Compensation expense recorded in the GL for that period. The column labeled "7/1/14-6/30/15" used in the 2 year average calculation adjusts GL expense for the following items:

   1. Removes the impact of out of period adjustments resulting from Mar-14 J903 and Feb-14 J028A (these amounts are shown on page 3 of the pro forma adjustment – columns labeled "Adjust J903 Mar-14" and "Adjust J028A Feb-14"). See the response to STF 11.15 for more information on these adjustments.

   2. Adjusts for capitalized A&G (this amount is shown on page 3 of the pro forma adjustment – column labeled "Adjust FERC 0920").

   3. Adjusts for officer incentive compensation originally expensed to FERC 426, which beginning in 2015 is now being allocated to various O&M FERC accounts (this amount is shown on page 3 of the pro forma adjustment – column labeled "Adjust FERC 0426).

   4. Adjusts for wage increases at 2% through 2017 (this amount is shown on page 3 of the pro forma adjustment – column labeled "Adjust Wage Increase").

   5. The resulting calendar year amount for 2014 after the above adjustments was then prorated for half year to arrive at the adjusted 7/1/14-6/30/15 amount.

b. All of the adjustments noted in a. above are reflected on page 3 when calculating the 2 year average, which is what was used to determine the pro forma adjustment amount. (e.g. we took the actual Short Term Incentive Compensation Expense for the Test Year, and then adjusted that amount to a 2 year average that factored in all the adjustments noted in a. above).

RESPONDENT:

Georgia Hale

WITNESS:

Frank Marino

TUCSON ELECTRIC POWER COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUN 30, 2015

ADJUSTMENT NAME:	Pension & Benefits Adjustment
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	March 10, 2016
PREPARED BY:	Miho Churei
CHECKED BY:	Brian Brumfield
REVIEWED BY:	

FERC ACCT	FERC ACCOUNT DESCRIPTION	Total Company DEBIT	Total Company CREDIT	ACC Jurisdictional DEBIT	ACC Jurisdictional CREDIT
926	Pension & Benefits	$3,008,126		$2,524,050	
	ENTRY TOTAL	$3,008,126	$0	$2,524,050	$0
	NET ENTRY	$3,008,126		$2,524,050	

Reason for Adjustment
To adjust operating expenses for the test year based on the most recent pension actuarial valuation and benefits expense based on calculated benefit rates for 2015.

Tucson Electric Power Company
Pension & Benefits Expense Adjustment
Test Year Ended JUN 30, 2015

Pension

		Total	
2014 Actuarial Net Benefit Cost			
Union Plan	2a	3,259,904	
Salaried Plan	3.1a	3,888,541	
Total Actuarial Expense for 2014 Year		7,148,445	a
2015 Net Benefit Cost			
Union Plan	2b	4,583,089	
Salaried Plan	3a	6,791,080	
Total 2015 Actuarial Expense		11,374,169	b
Increase in Pension Expense Based on Most Recent Actuarial Report		4,225,724	=b-a
Exclude SGS Units 1, 3, 4 Average Payroll @ 27.7%		(1,170,526)	
		3,055,198	
		59.7%	
Pension Expense Adjustment Required		1,823,953	
SERP Expense Adjustment Required		584,904	
Total Pension Adjustment		2,388,857	

Benefits

Exp Type		July-14 - Jun-15	
062	P/R Deduct-Benefits	(15,607,302)	
081	401k	5,316,704	
082	Medical Insurance	20,805,424	
083	Dental Insurance	949,970	
084	Life Insurance	748,598	
086	Other Benefits	12,294,075	
090	LTD - Long Term Disability Classified Employee	204,355	
091	LTD - Long Term Disability Unclassified Employee	336,308	
156	Contractor Services	627,660	
Grand Total		25,675,792	c
2% Increase 2016		26,189,308	d=c*1.02
2% Increase 2017		26,713,094	e=d*1.02
Adjusted from TY		1,037,302	=e-c
Payroll Charged to O&M (%) - Per Payroll by Function Report		59.7%	
Total Benefits Adjustment		619,269	

Tucson Electric Power Company
Pension Expense Adjustment - Supplemental Executive Retirement Plan (SERP)
Test Year Ended JUN 30, 2015

	2015
Expense per Actuarial Report	1,396,547
TEP allocation % (Massachusetts Formula)	80.90%
TEP Expense Per Actuarial Report	1,129,807
TEP Test Year - Included in O&M Per GL	(564,903)
SERP Adjustment	564,904

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 21, 2016

STF 7.15

Pension and Benefits:

Direct Testimony of Frank Marino, page 32, lines an17-21 and UDR 1.001 Workpaper Income-Pension & Benefits: Mr. Marino states that the Pension and Benefit adjustment includes current pension, Company's share of contributions to the employees' 401(k) plan, medical, dental, vision, life and long-term disability benefit expense levels. The workpaper for the Pension & Benefit adjustment appears to only include qualified retirement pension costs and SERP. Was an adjustment made for the Company's share of contributions to the employees' 401(k) plan, medical, dental, vision, life and long-term disability benefit expense levels? If so, please provide the adjustment workpapers.

RESPONSE:

Please see UDR 1.001, as supplemented on March 18, 2016.

RESPONDENT:

Brian Brumfield

WITNESS:

Frank Marino

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 2, 2016

RUCO 7.06

Director and Officers ("D&O") Insurance – Please answer the following questions as they relate to D&O insurance that the Company is seeking to recover in the test year:

a. What is the amount of prepaid D&O insurance included in working capital?

b. Is prepaid D&O insurance included anywhere else in rate base? If so, provide the amount and rate base category.

c. What is the amount of D&O expense recorded in test year operating expenses?

d. In c. above provide the FERC operating expense accounts along with the amounts recorded in each (e.g. administration).

RESPONSE: **April 18, 2016**

TEP is in the process of gathering this information and will provide it as soon as possible.

RESPONDENT:

Rigo Ramirez / Georgia Hale

WITNESS:

Frank Marino

SUPPLEMENTAL RESPONSE: **May 2, 2016**

a. There is $41,658 of D&O insurance included in working capital.

b. No.

c. $50,306. Please see STF 7.18.

d. $50,306 in FERC Account 925.

RESPONDENT:

Rigo Ramirez / Georgia Hale

WITNESS:

Dallas Dukes

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 21, 2016

STF 7.18

D&O Insurance:

Reference UDR 1.059. What is the amount of D&O insurance the Company is requesting to recover in this rate case? Please include the amount in expenses and the amount prepaid included in ratebase.

RESPONSE:

TEP is requesting $50,306 recovery of D&O insurance expense in this rate case.

D&O insurance - FERC 925 Account 78000	$	973,448
Pro Forma Adjustment Income - Fortis Merger Operating Income Adjustment		(923,142)
Amount of D&O Liability Insurance in the test year	$	50,306

There is no prepaid D&O insurance included in rate base.

The amounts provided in UDR 1.059 represented unadjusted book balances.

D&O insurance expense in the amount of $923,142 was removed via the pro forma adjustment: **Income – Fortis Merger Operating Income Adjustment** previously supplied under UDR 1.001.

RESPONDENT:

Anne Liu

WITNESS:

Dallas Dukes

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO AECC TENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 18, 2016

AECC 10.1

Legal expenses.

a. Please identify by FERC account the amount of outside legal expense included in the test year retail revenue requirement.

b. Are there any differences between TEP's per-books outside legal expense and the amount included in the test year retail revenue requirement? If so, please show where these adjustments are presented in TEP's filing.

c. Please identify by FERC account the amount of outside legal expense included in TEP's requested test year retail revenue requirement in Docket No. E-01993A-12-0291.

d. Please identify by FERC account the amount of outside legal expense incurred by TEP in each of the following years: 2012, 2013, and 2014.

e. Please refer to the Direct Testimony of Michael E. Sheehan, p. 45, lines 18-19. Are any of the outside legal expenses associated with the co-owners and former lessors of Springerville Unit 1 included in the test year retail revenue requirement? If so, please identify this amount, indicate the docket number(s) of the cases, and explain the rationale for recovering these expenses from ratepayers.

RESPONSE:

a. Please see AECC 10.1a Legal Expenses.xlxs. The Excel file is <u>not</u> identified by Bates numbers.

b. The differences between TEP's books outside legal expense and the amount included in the test year are identified in the file referenced in AECC 10.1a.

c. Please see AECC 10.1c Legal Expenses.xlxs. The Excel file is <u>not</u> identified by Bates numbers.

d. Please see AECC 10.1d Legal Expenses.xlxs. The Excel file is <u>not</u> identified by Bates numbers.

e Yes. There is $1,340,437 of outside legal expenses associated with the co-owners and former lessors of Springerville Unit 1 included in the test year retail revenue requirement. Below is a list of the case numbers and docket number:

Alterna Springerville LLC, LDVF1 TEP LLC, Wilmington Trust Co. and William J. Wade v. TEP
FERC Dkt. No. EL15-17-000

Alterna Springerville LLC, LDVF1 TEP LLC, Wilmington Trust Co. and William J. Wade v. TEP
Case No. 653898/2014
New York County Supreme Court

Alterna Springerville LLC, LDVF1 TEP LLC (via Wilmington Trust Company and William J. Wade as Trustees)
Case No. 01-15-0003-7373
American Arbitration Association

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO AECC TENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 18, 2016

TEP v. Alterna Springerville LLC, LDVF1 TEP LLC, Wilmington Trust Co. and William J. Wade Consolidated Matter
Case No. 01-15-0003-2729
American Arbitration Association New York

The rationale for recovery is that these legal expenses were necessary in order to acquire the interests in SGS Unit 1. As such, they are considered transaction costs for the acquisition to provide service to customers.

RESPONDENT:

Rigo Ramirez

WITNESS:

Dallas Dukes

Tucson Electric Power
Legal Expenses
AECC 10.1a

FERC	Test Year Unadjusted Balance	REST & DSM Adjustment	Springerville Units 3 & 4	Power Supply Management	Test Year Adjusted Balance
0500	1,115.00	-	-	-	1,115.00
0502	-	-	-	-	-
0506	4,789.50	-	(2,394.72)	-	2,394.78
0556	-	-	-	-	-
0560	203.50	-	-	-	203.50
0590	-	-	-	-	-
0903	31,346.36	-	-	-	31,346.36
0908	16,945.95	-	-	-	16,945.95
0923	3,483,179.46	(357,949.73)	-	(22,619.00)	3,102,610.73
0926	101,041.56	-	-	-	101,041.56
	3,638,621.33	(357,949.73)	(2,394.72)	(22,619.00)	3,255,657.88

Tucson Electric Power
Legal Expenses
AECC 10.1c

FERC	Unadjusted Calendar Yr. 2011	REST & DSM	Springerville Units 3 & 4	Adjusted Calendar Yr. 2011
0417	(8,323.10)	-	8,323.10	-
0514	76,822.13	-	-	76,822.13
0556	5,410.85	-	-	5,410.85
0903	20,117.18	-	-	20,117.18
0908	1,849.00	-	-	1,849.00
0923	1,925,765.71	(58,051.48)	(4,161.54)	1,863,552.69
0926	320,820.19	-		320,820.19
	2,342,461.96	(58,051.48)	4,161.56	2,288,572.04

Tucson Electric Power
Legal Expenses
AECC 10.1d

FERC	DEC-12	DEC-13	DEC-14
0500	-	12,636.25	62,575.08
0502	28,676.25	-	-
0506	-	-	4,789.50
0556	3,382.00	72.00	-
0560	560.00	17,828.92	869.50
0590	-	777.00	-
0903	32,374.88	27,586.75	36,146.66
0908	117,158.21	11,708.51	14,523.00
0923	1,672,679.97	1,445,192.93	2,279,615.48
0926	48,438.70	185,733.53	236,822.27
	1,903,270.01	1,701,535.89	2,635,341.49

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S EIGHTEENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 13, 2016

STF 18.1

Legal Expenses: Follow up to response to AECC 10.1. The Company stated there is $1.34 million in the test year for outside legal expenses associated with the co-owners and former lessors of Springerville Unit 1.

a. With the settlement of the disputes with the co-owners and TEP's acquisition of Unit 1, will TEP receive any reimbursement of these expenses?

b. The Company's rationale for recovery is that these expenses were necessary to acquire interests in Unit 1 and, as such, are considered transaction costs. Does the Company intend to capitalize these costs?

RESPONSE:

a. No.

b. No.

RESPONDENT:

Rigo Ramirez

WITNESS:

Dallas Dukes

TUCSON ELECTRIC POWER COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2015

ADJUSTMENT NAME:	Rate Case Expense
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	July 24, 2015
PREPARED BY:	Anne Liu
CHECKED BY:	Rigo Ramirez
REVIEWED BY:	David Lewis

		Total Company		ACC Jurisdictional	
FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT	DEBIT	CREDIT
928	Regulatory Expense	TA $396,667		$332,834	
407.3	Regulatory Asset Amortization		TB $225,000		$225,000
	ENTRY TOTAL	$396,667	$225,000	$332,834	$225,000
	NET ENTRY	$171,667		$107,834	

Reason for Adjustment

To remove book amortization of rate case expense in the test year and to include an estimate of outside expenditures for the rate case expense of $1,190,000 total expense amortized over three years.

TUCSON ELECTRIC POWER COMPANY
RATE CASE EXPENSE
FOR THE TEST YEAR ENDED JUNE 30, 2015

Outside Counsel	$600,000
Depreciation Study	$180,000
Rate Design Study	$225,000
Outside Rate Case Consultant	$85,000
Cost of Equity Study	$100,000
Total Estimated Expense	$1,190,000
Amortization per year (3 years)	$396,667 A
Less Test Year Amortization	2A ($225,000) B
Pro Forma Rate Case Expense Amortization Adjustment	$171,667

TEP(0322)003385

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 18, 2016

RUCO 7.19

Bids/Request for Proposals ("RFPs") – Did the Company procure bids/RFPs for the following rate case witnesses:

a. Cost of Capital Witness

b. Outside Attorney

c. Depreciation Expert

If so, please provide a brief narrative of the competitive bidding process (e.g. how many vendors applied) and how the witnesses were selected.

RESPONSE:

No, as it is not, nor has it ever been a requirement to procure bids/RFPs for such specialized services.

RESPONDENT:

TEP Legal Department

WITNESS:

Frank Marino

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S EIGHTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 18, 2016

STF 8.1

Rate Case Expense: The rate case expense provided with the application was an estimate. While it may still partially be an estimate, please provide the rate case expense as of the current date, including both current actual costs with supporting documentation and still projected costs in at least as much detail as provided originally with the application.

RESPONSE:

TUCSON ELECTRIC POWER COMPANY
RATE CASE EXPENSE
AS INCURRED through Feb 29, 2016

	Actuals	Revised Projections
Outside Counsel	105,887.19	600,000.00
Depreciation Study	152,715.00	200,000.00
Rate Design Study	145,943.14	225,000.00
Outside Rate Case Consultant	44,801.79	85,000.00
Cost of Equity Study	51,551.01	100,000.00
Total Estimated Expense	$500,898.13	$1,210,000.00

RESPONDENT:

Bernadette Porter

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 4, 2016

RUCO 5.4

Rate Case Expense – Please provide the rate case expense authorized by the Commission in the Company's last three rate cases.

RESPONSE:

Please see RUCO 5.4 Prior Rate Case Expense Authorized.xlsx. The Excel file is not identified by Bates numbers.

RESPONDENT:

Rigo Ramirez

WITNESS:

Dallas Dukes

TUCSON ELECTRIC POWER COMPANY
RATE CASE EXPENSE
Amounts Authorized by the Commission

Test Year	Amount
2012	$ 900,000
2007	$ 900,000

The company did not seek recovery of its Rate Case Exenses prior to the 2007 Rate Case.

TUCSON ELECTRIC POWER COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2015

ADJUSTMENT NAME:	Income - Credit Card Processing Fees
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	October 10, 2015
PREPARED BY:	Rigo Ramirez
CHECKED BY:	
REVIEWED BY:	

FERC ACCT	FERC ACCOUNT DESCRIPTION	Total Company DEBIT	Total Company CREDIT	ACC Jurisdictional DEBIT	ACC Jurisdictional CREDIT
903	Customer Records & Collection Expenses	$3,475,500		$3,475,500	
	ENTRY TOTAL	$3,475,500	$0	$3,475,500	$0
	NET ENTRY	$3,475,500		$3,475,500	

Reason for Adjustment
To add a portion of customer credit card fees into utility rates.

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S EIGHTEENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 13, 2016

STF 18.2

Miscellaneous Expenses: Follow up to response to STF 12.03. Please explain the specific nature of the expenses included in the following Miscellaneous General Expenses. Also indicate whether any of these dollars are part of a pro forma adjustment included within the Company's application.

a. Membership Dues - $ 2,339,286

b. Administrative Labor Remote - $1,326,326

c. Other A&G Expense - $585,113

d. Printing & Mailing - $731,146

e. Wages - $216,021

f. Material & Supplies - $16,116

RESPONSE:

a.-f. Please see STF 18.2 Miscellaneous Expenses.xlsx for details. The Excel file is not identified by Bates numbers.

RESPONDENT:

Rigo Ramirez

WITNESS:

Dallas Dukes / Frank Marino

Tucson Electric Power Company
Miscellaneous Expenses
STF 18.2

a. Membership Dues

Vendor	Description	Unadjusted FERC 930	Membership Dues Pro Forma (1)	SPV 3&4 Dues Pro Forma (2)	SPV 1 Pro Forma (3)	Payroll Pro Forma (4)	Fortis Pro Forma (5)	Adjusted FERC 930
Western Electricity Coordinating Council	2012 Annual Net Energy for Lad and 2014 Assessments	263,420						263,420
Western Electricity Coordinating Council	2015 Peak Reliability Assessment	381,221						381,221
Edison Electric Institute	Membership Dues	444,489	(74,184)					370,305
Tucson Metropolitan Chamber of Commerce	Annual Membership and Sponsorship Dues	24,010						24,010
Southern Arizona Leadership Council	Annual Membership and Dues	18,750						18,750
New Mexico Utility Shareholders Alliance	Annual Membership Dues	15,540						15,540
Tucson Regional Economic Opportunity	Chairman's Circle Membership	50,000						50,000
Electric Power Research Institute	Energy and Environmental Policy	129,648						129,648
Edison Electric Institute	UARG Membership Dues	140,309						140,309
Edison Electric Institute	USWAG Membership Dues	32,400	(5,184)					27,216
West Associates	Dues Assessment	17,029						17,029
Western Electricity Coordinating Council	Unscheduled Flow Mitigation	14,411						14,411
Western Electricity Coordinating Council	2014 Peak Reliability Special Assessment	77,622						77,622
Western Electricity Coordinating Council	Statutory Assessment	356,072						356,072
North American Electric Reliability Corporation	Statutory Assessment	178,997						178,997
Western Interconnection Regional Advisory Body	Statutory Assessment	13,995						13,995
Other Dues and Charges		269,622	(7,649)	(1,232)				260,741
		2,427,535	(87,017)	(1,232)	-	-	-	2,339,286

b. Administrative Labor Expenses

Vendor	Description	Unadjusted FERC 930	Membership Dues Pro Forma (1)	SPV 3&4 Dues Pro Forma (2)	SPV 1 Pro Forma (3)	Payroll Pro Forma (4)	Fortis Pro Forma (5)	Adjusted FERC 930
APS charges for the Four Corners Generating Station	Similar charges for the Navajo and San Juan generating stations are recorded under a different FERC Account	1,317,654						1,317,654
Other Miscellaneous Charges		8,672						8,672
		1,326,326	-	-	-	-	-	1,326,326

c. Other A&G Expense

Vendor	Description	Unadjusted FERC 930	Membership Dues Pro Forma (1)	SPV 3&4 Dues Pro Forma (2)	SPV 1 Pro Forma (3)	Payroll Pro Forma (4)	Fortis Pro Forma (5)	Adjusted FERC 930
Tucson Festival of Books	Sponsorship	10,000						10,000
University of Arizona School of Renewable Resources	Sponsorship	10,000						10,000
The Physics Factory	Sponsorship	20,000						20,000
Southern Arizona Research Science and Engineering Foundation	Sponsorship	5,000						5,000
Tucson Children's Museum	Tour and buses	8,000						8,000
Corporate Intercompany Charges	Intercompany corporate payroll and miscellaneous employee charges	1,256,551		(3,000)	(37,967)		(683,471)	532,113
		1,309,551	-	(3,000)	(37,967)	-	(683,471)	585,113

d. Printing & Mailing

Vendor	Description	Unadjusted FERC 930	Membership Dues Pro Forma (1)	SPV 3&4 Dues Pro Forma (2)	SPV 1 Pro Forma (3)	Payroll Pro Forma (4)	Fortis Pro Forma (5)	Adjusted FERC 930
Standard & Poor's Rating Services	Analytical services rendered in connection with $1.3 Bil debt outstanding	80,000						80,000
Industrial Development Authority of the County of Pima	Administrative expenses incurred by the IDA for all matters relating to this Industrial Development Revenue Bond Issue for the Period July 1, 2013 through June 30,2014	100,000						100,000

Standard & Poor's Rating Services	Analytical services rendered in connection with 3.05% Notes due 2025	184,500						184,500
Moody's Investor Services	Credit Monitoring Service Base Fee	160,000						160,000
Union Bank	Springerville Common Lease - Admin Agent Fee	50,000						50,000
Standard & Poor's Rating Services	Analytical services rendered in connection with Corporate Credit Rating Annual Surveillance Fee	82,000						82,000
Wilmington Trust	Springerville Common Lease - Admin Fees	22,350						22,350
Union Bank	Annual Agency Fees	70,000						70,000
Other Miscellaneous Charges and Offsets		(17,704)						(17,704)
		731,146	-	-	-	-	-	731,146

e. Wages

Vendor	Description	Unadjusted FERC 930	Membership Dues Pro Forma (1)	SPV 3&4 Dues Pro Forma (2)	SPV 1 Pro Forma (3)	Payroll Pro Forma (4)	Fortis Pro Forma (5)	Adjusted FERC 930
Employee Payroll Charges	Direct employee payroll charges to general and administratve expenses-FERC 930	208,004				8,017		216,021

f. Material & Supplies

Vendor	Description	Unadjusted FERC 930	Membership Dues Pro Forma (1)	SPV 3&4 Dues Pro Forma (2)	SPV 1 Pro Forma (3)	Payroll Pro Forma (4)	Fortis Pro Forma (5)	Adjusted FERC 930
JCPenney	Employee Gift Certificates	2,500						2,500
Red Park Zoo	Rental & food costs for TEP CAT recognition event	9,145						9,145
Other Miscellaneous Charges		4,471						4,471
		16,116	-	-	-	-	-	16,116

Notes:

(1) See Income-Membership Dues.xlsm pro forma
(2) See Income - Springerville Units 3 and 4.xlsm pro forma
(3) See Income - Springerville Unit 1.xlsm pro forma
(4) See Income - Payroll Expense.xlsm pro forma
(5) See Income - Fortis Merger Operating Income Adjustment.xlsm pro forma

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO AECC THIRTEENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 25, 2016

AECC 13.3

Please refer to TEP's Income – Payroll Expense adjustment workpaper, the Exec Salary tab. The Note states:

The Fortis Merger Agreement states that if the number of Senior Management Personnel in the test year is less than 11, total compensation will be reduced proportionately.

The number of Senior Management Personnel remains at 11 during the test year. No proportional reduction is needed.

Please reconcile this statement with Mr. Dukes' Direct Testimony, page 48, lines 11-12.

RESPONSE:

In reviewing the Direct Testimony of Dallas Dukes, the Company found the cited quote to be that of the Direct Testimony of Frank Marino. During a transitional period in the Test Year, we temporarily had 10 officers. Another officer resigned and left the Company in July 2015 and, two officers were subsequently appointed. At the date of the filing, there were 11 officers.

RESPONDENT:

Gabrielle Camacho / Georgia Hale

WITNESS:

Frank Marino

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO AECC THIRTEENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 25, 2016

AECC 13.2

Please refer to the Direct Testimony of Dallas Dukes, page 48, lines 11-15, which states:

As of the end of the Test Year there were 10 executive officers of UNS Energy. This is one less than the number of executive officers as of August 12, 2014, the date of Decision No. 74689 approving the merger. Therefore, pursuant to Condition 11, the portion of the compensation for those Senior Management Personnel that is allocable to TEP has not increased.

For each month of the test year, please provide the actual number of UNS Energy Senior Management Personnel.

RESPONSE:

In reviewing the Direct Testimony of Dallas Dukes, the Company found the cited quote to be that of the Direct Testimony of Frank Marino, page 48, lines 11-15. Please see the table below for the actual number of TEP Senior Management Personnel by month,

Month	Officer Count
Jul-14	11
Aug-14	11
Sep-14	11
Oct-14	10
Nov-14	10
Dec-14	10
Jan-15	10
Feb-15	10
Mar-15	10
Apr-15	10
May-15	10
Jun-15	10

RESPONDENT:

Gabrielle Camacho

WITNESS:

Frank Marino

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S THIRTEENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 21, 2016

STF 13.2

SGS Unit 1: During discussion with Company Personnel at Springerville Generating station on 31 March 2016, representatives from Blue Ridge Consulting were informed that the co-owners (50.5%) of Unit 1 have settled the outstanding issues with TEP and (START CONFIDENTIAL) that TEP will likely purchase the remaining 50.5% of unit 1 from the other co-owners. Please confirm that understanding. (END CONFIDENTIAL).

RESPONSE:

On February 29, 2016, TEP entered into an agreement with the third-party owners of 50.5% of Unit 1 for the settlement and release of asserted claims and the purchase and sale of beneficial interests in Unit 1 (Agreement). The Agreement provides that TEP will purchase the third-party owners' 50.5% undivided interest in Unit 1 for $85 million and the third-party owners will pay TEP $12.5 million for operating costs related to Unit 1 incurred on behalf of the third-party owners. Upon completion of the purchase, all outstanding disputes and pending litigation and arbitration proceedings between TEP and the third-party owners will be dismissed with prejudice.

The purchase of third-party owners' undivided interest in Unit 1 is subject to, among other things, Federal Energy Regulatory Commission approval and satisfaction of other customary closing conditions.

RESPONDENT:

Kentton Grant / Todd Hixon

WITNESS:

Kentton Grant

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S THIRTEENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 21, 2016

STF 13.3

SGS Unit 1: (START CONFIDENTIAL) Please provide an estimate of when the expected purchase of Unit 1 will be consummated. (END CONFIDENTIAL).

RESPONSE:

TEP expects the purchase of Unit 1 to close in the second quarter of 2016.

RESPONDENT:

Kentton Grant / Todd Hixon

WITNESS:

Kentton Grant

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SEVENTEENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 13, 2016

STF 17.05

SGS Unit 1 O&M: Reference STF 13.2. With the pending agreement for TEP to buy out the other co-owners' interest in Unit 1 (expecting to close in the 2nd Quarter 2016), what is the Company intention regarding its adjustment eliminating the O&M costs associated with the 50.5% share of those other co-owners in Unit 1.

RESPONSE:

As described in the direct testimonies of Michael Sheehan and Kentton Grant, the Company proposed recovering the O&M costs for the 50.5% share of SGS Unit 1 through the PPFAC, commencing on the effective date of the Commission's rate order. That proposal, which predated TEP's agreement to purchase the 50.5% share, stated that PPFAC recovery would only apply if the generating capacity was available to meet retail customer demand. The Company still supports this recovery method, but is also amenable to O&M recovery through non-fuel rates.

RESPONDENT:

Kentton Grant

WITNESS:

Kentton Grant/Michael Sheehan

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SEVENTEENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 13, 2016

STF 17.06

SGS Leasehold Improvements (continued amortization) and SGS CHF Adjustment: The Company recorded a regulatory asset for $23.887 for the SGS leasehold improvements.

a. Please explain why regulatory asset treatment and inclusion in rate base is appropriate for the other 50.5% co-owner share of leasehold improvements.

b. Was this amount included as a receivable?

c. What is the impact of TEP pending purchase of the 50.5% co-owners share of Unit 1 on the regulatory asset and the Company's request for continued amortization of these costs?

RESPONSE:

a. The referenced leasehold improvements represented capital expenditures made during the term of the SGS Unit 1 lease that were required for the continued operation of SGS Unit 1. Had those investments not been made, the 49.5% of SGS Unit 1 currently owned by TEP would not be operable. Since these expenditures were reasonable and necessary at the time they were made, they should be subject to continued rate recovery. The Commission allowed rate base treatment of SGS Unit 1 leasehold improvements in the Company's last two rate orders. In the last rate case, TEP proposed recovering the leasehold improvements using a 10-year amortization period, instead of recovering them over the remaining life of the SGS Unit 1 lease (which expired January 1, 2015). This was done in order to limit the rate impact on customers, and was incorporated in the rate settlement agreement approved by the Commission. If those same leasehold improvements were now disallowed from rate base, the Company would essentially be penalized for making a proposal that benefited customers in the last TEP rate case.

b. No

c. The Company still supports its original request to recover the leasehold improvements using the established amortization period. However, the Company is also amenable to recovering them as a plant investment over the remaining useful life of SGS Unit 1.

RESPONDENT:

Kentton Grant

WITNESS:

Kentton Grant

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S NINTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
____, 2016

RUCO 9.09

SGS 50.5 Percent Ownership by Other Parties in Unit 1 – On page 33, line 24, Company witness Kentton C. Grant discusses the current litigation with the parties who have an ownership stake in SGS unit 1. Please answer the following questions based on his discussion of remaining 50.5 percent interest in SGS unit 1:

a. Who are the other owners in SGS Unit 1, and state their percentage ownership of the 50.5 percent?

b. Mr. Grant states that the Company began dispatching the owners share on the open market. Please provide the amount of revenue generated by theses sales by month. In addition, please include any worksheet sheets or calculations to substantiate the Company's revenue amounts.

c. Were any of these revenues in b. recovered through the Company's Purchased Power and Fuel Adjustment Clause ("PPFAC")? If no, why not.

d. To clarify the Company also intends to recover the other parties' ownership operation and maintenance ("O&M") costs through the PPFAC?

e. In d. does the Company also intend to use June 2015 as a starting point to recovery the third party O&M costs? If no, what date does the Company intend to use as its starting point?

f. Has the Company already started collecting the other parties O&M costs through the PPFAC?

g. What is the amount by month of O&M costs still owed by the other parties in unit 1? In addition, please provide the amount of CHC and Common Facilities and Lease hold improvement costs, and any other costs still owed by the other parties by month.

h. Subsequently, have the parties settled with TEP? If so, what are the terms of the settlement, and how does the Company propose to treat the delinquent amounts. In addition, please provide a copy of the settlement agreement.

i. Does TEP now own 100 percent in unit 1? If no, when does TEP expect to own 100 percent in unit 1?

j. Why does the Company want to rate base the delinquent leasehold improvement amounts from the other parties instead of treating it as an operating lease, similar to the common facilities?

RESPONSE:

a. Alterna Springerville LLC, an affiliate of Alterna Capital Partners, owns a 43.0693% undivided interest in SGS Unit 1. The other 7.4257% is owned by LDVF1 TEP LLC, an affiliate of the Fortress Investment Group.

b. THE FILE LISTED BELOW CONTAINS COMPETITIVELY-SENSITIVE CONFIDENTIAL INFORMATION THAT IS ONLY BEING PROVIDED TO THE REQUESTING PARTY PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S NINTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
____, 2016

Please see RUCO 9.09 Competitively Sensitive Confidential.pdf, for the sales recorded from dispatching the 50.5% share of SGS Unit 1 are based on counterparty transactions entered into our power trading system. Sale amounts are derived from negotiated contract terms.

c. No. This portion of SGS Unit 1 was not a system resource available for dispatch to meet the needs of TEP's retail customers.

d. As described in the direct testimonies of Mr. Grant and Mr. Sheehan, the Company is only requesting PPFAC recovery of O&M costs associated with this 50.5% share if the generation is available for dispatch to meet retail customer needs.

e. No. Assuming the condition described in part (d) above is met, the Company is requesting that O&M recovery through the PPFAC begin upon implementation of new rates in this rate case.

f. No.

g. THE FILE LISTED BELOW CONTAINS COMPETITIVELY-SENSITIVE CONFIDENTIAL INFORMATION THAT IS ONLY BEING PROVIDED TO THE REQUESTING PARTY PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

See attached file RUCO 9.09(g) Costs due from SGS U1 50.5% Owners–Confidential Competitively Sensitive.xlsx.

h. Yes. Please see the response to STF 13.2. As for treatment of unreimbursed O&M costs, they would be written off by the Company.

i. No. The Company is awaiting FERC approval of the proposed purchase. If approved, TEP expects to close the purchase in the second quarter of 2016.

j. Leasehold improvements are fundamentally different from lease payments. Leasehold improvements represent replacements and betterments of leased utility plant. The Commission has previously allowed for rate base treatment of Springerville leasehold improvements in the Company's last two rate orders.

RESPONDENT:

Kentton Grant/Georgia Hale (b,g)

WITNESS:

Kentton Grant

RUCO 9.09 (g)
SGS Unit 1 Participant Owners
Schedule of Costs Jan-15 through Mar-16
($ in thousands)

	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	2015 Total	Jan-16	Feb-16	Mar-16	2016 Total	Cumulative Total
Operating	$ 1,698	$ 1,981	$ 1,865	$ 2,008	$ 1,733	$ 1,899	$ 1,979	$ 1,697	$ 2,156	$ 1,883	$ 1,693	$ 1,942	$ 22,533	$ 1,730	$ 1,975	$ 2,695	$ 6,400	$ 28,933
Capital	30	163	43	299	258	175	515	171	440	277	943	1,229	4,545	311	614	1,116	2,041	6,585
Total	$ 1,728	$ 2,145	$ 1,907	$ 2,307	$ 1,991	$ 2,074	$ 2,494	$ 1,868	$ 2,596	$ 2,159	$ 2,636	$ 3,171	$ 27,078	$ 2,041	$ 2,589	$ 3,811	$ 8,441	$ 35,519

/Users/tracymullinax/ownCloud/Projects/Arizona TEP/DMS/Responses/RUCO/RUCO 9.09 (g) Costs due from SGS U1 50.5% Owners-Confidential Competitively Sensitive.xlsx

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S NINTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
____, 2016

RUCO 9.10

SGS Ownership by Other Parties - Please answer the following questions as they relate to all four SGS units:

a. Please provide a list of the owners and their percentage interest in each of the SGS units?
b. Please provide a list of the owners and their percentage interest by year going back to 2005.
c. Please provide a list of the owners and their percentage interest by year projecting out to 2025.

RESPONSE:

a. Unit 1: TEP 49.5%, Alterna Springerville LLC 43.0693%, LDVF1 TEP LLC 7.4257%

Unit 2: San Carlos Resources, Inc., a wholly-owned subsidiary of TEP

Unit 3: Springerville Unit 3 Holding LLC, Lessor to Tri-State Generation & Transmission Association

Unit 4: Salt River Project

b. Same as (a), except for Unit 1. The following undivided interests in SGS Unit 1 were owned by the parties listed below for the time periods indicated:

43.0693%	Alterna Springerville LLC (2009 – present)
	Philip Morris Capital Corporation (2005 – 2009)
7.4257%	LDVF1 TEP LLC (2005 – present)
	CILCORP Lease Management, Inc. (2005)
17.6804%	TEP (2015 – present)
	Daimler Capital Services LLC (2005 – 2015)
10.6082%	TEP (2015 – present)
	Pacific Harbor Capital, Inc. (2005 – 2015)
7.0721%	TEP (2015 – present)
	MWR Capital, Inc. (2005 – 2015)
14.1443%	TEP (2006 – present)
	US West Financial Services, Inc. (2005 – 2006)

c. Same as (a) except for Unit 1, which is expected to be 100% owned by TEP beginning in mid-2016.

RESPONDENT:

Kentton Grant

WITNESS:

Kentton Grant

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO AECC THIRTEENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 25, 2016

AECC 13.1

Follow-up to TEP's Supplemental Response to AECC Data Request 5.3.

a. Please provide the total UNS Energy Senior Management Personnel total compensation for the twelve month period preceding the date of the Fortis acquisition closing, separately stating the following components if applicable: base salary, pension, SERP, post-retirement benefits, medical/dental benefits, long-term incentive compensation, short-term incentive compensation, and any other components. Please indicate the percentage of the UNS Energy Senior Management Personnel total compensation allocable to TEP at the time of Fortis acquisition closing.

b. Please provide the unadjusted total UNS Energy Senior Management Personnel total compensation for the twelve months ended June 30, 2015, separately stating the following components if applicable: base salary, pension, SERP, post-retirement benefits, medical/dental benefits, long-term incentive compensation, short-term incentive compensation, and any other components. Please indicate the percentage of the UNS Energy Senior Management Personnel total compensation allocable to TEP.

c. Please provide TEP's proposed adjusted Senior Management Personnel total compensation allocable to TEP, including the proposed 2% payroll increases for 2016 and 2017 and all other proposed compensation-related adjustments, separately stating the following compensation components if applicable: base salary, pension, SERP, post-retirement benefits, medical/dental benefits, long-term incentive compensation, short-term incentive compensation, and any other components.

RESPONSE:

a. See attached file AECC 13.1 Sr. Mgmt Comp - Confidential.xlsx

b. See attached file AECC 13.1 Sr. Mgmt Comp - Confidential.xlsx

c. See attached file AECC 13.1 Sr. Mgmt Comp - Confidential.xlsx

RESPONDENT:

Gabrielle Camacho / Georgia Hale

WITNESS:

Frank Marino

DONNA H. MULLINAX

SCHEDULE DHM-47

PAGE 2

REDACTED

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-01933A-15-0322

DIRECT

TESTIMONY

OF

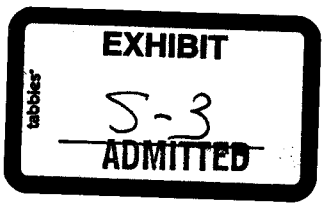
DAVID C. PARCELL

ON BEHALF OF

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSIONS

JUNE 3, 2016



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ATTACHMENT

David Parcell Resume.....ATTACHMENT 1

EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-15-0322 et. al.

Mr. Parcell's Direct Testimony provides an estimate of the cost of capital ("COC") for Tucson Electric Power Company ("TEP"). His COC recommendation is as follows:

	Percent	Cost	Return	
Long-Term Debt	51.31%	4.14%	2.12%	
Common Equity	48.69%	9.2-9.5%	4..48-4.63%	
Total	100.00%		6.60-6.75%	(6.68% Midpoint)

Mr. Parcell uses TEP's actual test year June 30, 2015 values of capital structure and cost of debt. This differs from TEP's proposal to use test year values adjusted for certain retirements of debt beyond the end of the test year.

The primary difference between Mr. Parcell's COC recommendations and the recommendation of TEP's COC witness (Ann E. Buckley) is the cost of common equity. Mr. Parcell recommends a cost of equity of 9.2 percent to 9.5 percent whereas Ms. Buckley recommends a 10.35 percent cost of equity.

Mr. Parcell's cost of equity recommendation is based upon his application of the following three cost of equity models:

	Range	Midpoint
Discounted Cash Flow ("DCF")	8.6-9.2%	8.9%
Capital Asset Pricing Model ("CAPM")	6.6-6.8%	6.7%
Comparable Earnings ("CE")	8.5-9.5%	9.0%

Mr. Parcell's 9.2 percent to 9.5 percent cost of equity recommendation reflects the upper end result of his DCF analyses and his CE analyses. His recommendation does not directly incorporate the CAPM results, which are lower; however, the CAPM results are an appropriate indicator of the continuing decline in the costs of capital, including the cost of equity.

Mr. Parcell's testimony also demonstrates that Ms. Buckley's cost of equity analyses overstates the cost of equity for electric utilities, including TEP. All of her analyses are shown to upward bias the cost of equity at the current time.

Mr. Parcell also provides a calculation of the Fair Value Rate Base Rate of Return. He provides two options for the Fair Value Increment for TEP – 1) a zero percent return on the FVRB increment, and 2) a 0.70 percent return on the FVRB increment. The values of the second option are utilized by Staff Witness Ms. Mullinax to develop the Fair Value Rate of Return for TEP.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is 1503 Santa Rosa Road, Suite 130, Richmond, Virginia 23229.

Q. Please summarize your educational background and professional experience.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. I have provided cost of capital ("COC") testimony in public utility ratemaking proceedings, dating back to 1972. In connection with this, I have previously filed testimony and/or testified in over 535 utility proceedings before more than 50 regulatory agencies in the United States and Canada. I have previously filed testimony and/or testified in more than 25 public utility proceedings before this Commission, most on behalf of the Utilities Division Staff. Attachment 1 provides a more complete description of my education and relevant work experience.

Q. What is the purpose of your testimony in this proceeding?

A. I have been retained by the Arizona Corporation Commission ("Commission") Utilities Division Staff ("Staff") to evaluate the COC aspects of the current filing of Tucson Electric Power Company ("TEP" or "Company"). I have performed independent studies and am making recommendations of the current COC for TEP. In addition, since TEP is a subsidiary of Fortis, Inc. ("Fortis"), I have also evaluated this entity in my analyses.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes, I have prepared one exhibit, made up of fifteen schedules, identified as schedule 1 through schedule 15. These schedules were prepared either by me or under my direction.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. What are your recommendations in this proceeding?

A. My overall COC recommendation for TEP is shown on Schedule 1 and is summarized as follows:

Item	%	Cost	Weighted Cost
Long-Term Debt	51.31%	4.14%	2.12%
Common Equity	48.69%	9.2-9.5%	4.48-4.63%
Total	100.00%		6.60-6.75%
			(6.68% Midpoint)

Q. Please summarize your analyses and conclusions.

A. This proceeding is concerned with TEP's regulated electric utility operations in Arizona. My analyses concern the Company's total COC. The first step in performing these analyses is to develop the appropriate capital structure. TEP proposes use of its June 30, 2015 test year (adjusted) capital structure. I use the Company's actual test year capital structure in my COC analyses.

The second step in a COC calculation is to determine the embedded cost rate of debt. I use TEP's actual test year 4.14 percent cost rate for long-term debt.

The third step in the COC calculation is to estimate the return on common equity ("ROE"). I employ three recognized methodologies to estimate TEP's ROE, each of which I apply to two proxy groups of electric utilities. These three methodologies and my findings are:

Methodology	Range
Discounted Cash Flow ("DCF")	8.6%-9.2% (8.9% mid-point)
Capital Asset Pricing Model ("CAPM")	6.5%-6.8% (6.65% mid-point)
Comparable Earnings ("CE")	8.5%-9.5% (9.0% mid-point)

Based upon these findings, I conclude that TEP's ROE is within a range of 9.2 percent to 9.5 percent (9.35 percent mid-point), which is based upon the upper end of the ranges of the results for the DCF and CE models.[1] I recommend the mid-point of this range, or 9.35 percent, as TEP's ROE.

Combining these three steps into the weighted COC results in an overall rate of return range of 6.60 percent to 6.75 percent (6.68 percent mid-point which incorporates a 9.35 percent ROE).

I also show that TEP's witness Ann E. Buckley has over-stated the Company's COC in her 10.35 percent ROE recommendation and 7.34 percent COC recommendation. Ms. Buckley's risk-premium and CAPM analyses are biased upward as a result of several improper adjustments and data sources she employs.

Finally, I provide a calculation of the Fair Value Rate Base ("FVRB") Rate of Return. I provide two options for the Fair Value Increment for TEP – 1) a zero percent return on the FVRB increment, and 2) a 0.70 percent return on the FVRB increment. The values of the second option are utilized by Staff Witness Ms. Mullinax to develop the Fair Value Rate of Return for TEP.

[1] As I indicate in a later section, my ROE recommendation does not directly incorporate the CAPM results, which I believe to be somewhat low at this time, relative to the DCF and CE results.

ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES

Q. What are the primary economic and legal principles that establish the standards for determining a fair rate of return for a regulated utility?

A. Public utility rates are normally established in a manner designed to allow the recovery of their costs, including capital costs. This is frequently referred to as "cost of service" ratemaking. Rates for regulated public utilities traditionally have been primarily established using the "rate base – rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets utilized (i.e. rate base) in providing service to their customers.

The rate base is derived from the asset side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners' equity side of the balance sheet as a percentage. Thus, the revenue impact of the COC is derived by multiplying the rate base by the rate of return, including income taxes.

The rate of return is developed from the COC, which is estimated by weighting the capital structure components (i.e. debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these values by their cost rates. This is also known as the weighted COC.

Technically, "fair rate of return" is a legal and accounting concept that refers to an ex post (after the fact) earned return on an asset base, while the COC is an economic and financial concept which refers to an ex ante (before the fact) expected, or required, return on a capital base. In regulatory proceedings, however, the two terms are often used interchangeably, and I have equated the two concepts in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and have an opportunity to earn comparable returns relative to similar risk investments. These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.

Although I am not a lawyer and I do not offer a legal opinion, my testimony is based on my understanding that two United States Supreme Court decisions provide the controlling standards for a fair rate of return. The first decision is Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923). In this decision, the Court stated:

> The annual rate that will constitute just compensation depends upon many circumstances and must be determined by the exercise of fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.

It is generally understood that the Bluefield decision established the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It also noted that required returns change over time, and there is an underlying assumption that the utility be operated efficiently.

The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1942). In that decision, the Court stated:

> The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and consumer interests . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By this standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

The three economic and financial parameters in the Bluefield and Hope decisions – comparable earnings, financial integrity, and capital attraction – reflect the economic criteria encompassed in the "opportunity cost" principle of economics. The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise on which regulation rests, namely, that it is intended to act as a surrogate for competition.

I understand that because Arizona is a "Fair Value" state, Hope and Bluefield do not set forth the legal requirements applicable to determining fair rate of return in Arizona. In Simms v. Round Valley Light & Power Company, 294 P.2d 378 (1956), the Arizona Supreme Court took exception to application of the following principle in Arizona since the Constitution mandates consideration of fair value:

> "In the Hope case the court, in testing the reasonableness of rates fixed by the Federal Power Commission under the Natural Gas Act, 15 U.S.C.A. Section 717 et seq., after holding that Congress had provided no formula by which just and reasonable rates were to be determined, ruled that it was the final result reached and not the method used in reaching the result that was

> controlling and that it was unimportant to 'determine the various permissible ways in which any rate base on which the return is computed might be arrived at'."

My testimony does not advocate that the Commission ignore the Simms holding in this regard, or the fair value of TEP property, which it is required to consider under Article 15, Section of the Arizona Constitution. Rather, I find the Hope and Bluefield decisions can be helpful in their discussion of comparable earnings, financial integrity and capital attraction. I note that TEP Witness Buckley also cites the Hope and Bluefield cases as guidelines for evaluating the COC for the Company.

Q. Is TEP requesting a "fair value" increment to this proceeding?

A. Yes, it is. TEP witness Buckley recommends a 5.64 percent fair value rate of return, which includes a fair value increment return on 1.42 percent.

Q. How can the Bluefield and Hope parameters be employed to estimate the COC for a utility?

A. Neither the courts nor economic/financial theory has developed exact and mechanical procedures for precisely determining the COC. This is the case because the COC is an opportunity cost and is prospective-looking, which dictates that it must be estimated. However, there are several useful models that can be employed to assist in estimating the ROE, which is the capital structure item that is the most difficult to determine. These include the DCF, CAPM, CE and risk premium ("RP") methods. I have not directly employed a RP model in my analyses although, as discussed later, my CAPM analysis is a form of the RP methodology. Each of these methodologies will be described in more detail later in my testimony.

GENERAL ECONOMIC CONDITIONS

Q. Are economic and financial conditions important in determining the COC for a public utility?

A. Yes. The COC, for both fixed-cost (debt and preferred stock) components and common equity, are determined in part by current and prospective economic and financial conditions. At any given time, each of the following factors has an influence on the COC:

- The level of economic activity (i.e., growth rate of the economy);
- The stage of the business cycle (i.e., recession, expansion, or transition);
- The level of inflation;
- The level and trend of interest rates; and
- Current and expected economic conditions.

My understanding is that this position is consistent with the Bluefield decision that noted "[a] rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally." Bluefield, 262 U.S. at 693.

Q. What indicators of economic and financial activity did you evaluate in your analyses?

A. I examined several sets of economic statistics from 1975 to the present. I chose this time period because it permits the evaluation of economic conditions over four full business cycles, allowing for an assessment of changes in long-term trends. Consideration of economic/financial conditions over a relatively long period of time allows me to assess how such conditions have had impacts on the level and trends of the COC. This period also

approximates the beginning and continuation of active rate case activities by public utilities, which generally began in the mid-1970s.

A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical (i.e., stage of business cycle) influences and, thus, permits a comparison of structural (or long-term) trends.

Q. Please describe the timeframes of the four prior business cycles and the current cycle.

A. The four prior complete cycles and current cycle cover the following periods:

Business Cycle	Expansion Cycle	Contraction Period
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Mar. 1991-Mar. 2001	Apr. 2001-Nov. 2001
2001-2009	Nov. 2001-Nov. 2007	Dec. 2007-June 2009
Current	July 2009-	

Source: National Bureau of Economic Research, "Business Cycle Expansions and Contractions."[2]

Q. Do you have any general observations concerning the recent trends in economic conditions and their impact on capital costs over this broad period?

A. Yes, I do. From the early 1980s until the end of 2007, the United States economy had enjoyed general prosperity and stability. This period had been characterized by longer economic expansions, relatively tame contractions, low and declining inflation, and declining interest rates and other capital costs.

[2] http://www.nber.org/cycles/cyclesmain.html.

However, in 2008 and 2009, the economy declined significantly, initially as a result of the 2007 collapse of the "sub-prime" mortgage market and the related liquidity crisis in the financial sector of the economy. Subsequently, this financial crisis intensified with a more broad-based decline which resulted in a dramatic decline in the U.S. financial sector, as well as many other components of the economy.

This decline has been described as the worst financial crisis since the Great Depression and has been referred to as the "Great Recession." Beginning in 2008, the U.S. and other governments implemented unprecedented actions to attempt to correct or minimize the scope and effects of this recession.

The recession reached its low point in mid-2009, when the economy began to expand again, although at a slow and uneven rate. However, the length and severity of the recession, as well as a relatively slow and uneven recovery, indicate that the impacts of the recession have been and will be felt for an extended period of time.

Q. Please describe recent and current economic and financial conditions and their impact on the COC.

A. One impact of the Great Recession has been a reduction in actual and expected investment returns and a corresponding reduction in the COC. This decline is evidenced by a decline in both short-term and long-term interest rates and the expectations of investors and is reflected in ROE model results (such as DCF, CAPM and CE). Regulatory agencies throughout the U.S. have recognized the decline in capital costs by authorizing lower ROEs for regulated utilities.

Schedule 2 shows several sets of relevant economic and financial statistics for the cited time periods. Pages 1 and 2 contain general macroeconomic statistics; pages 3 and 4 show interest rates; and pages 5 and 6 contain equity market statistics.

Pages 1 and 2 show that in 2007 the economy entered a significant decline, as indicated by the growth in real (i.e., adjusted for inflation) Gross Domestic Product ("GDP"), industrial production, and an increase in the unemployment rate. This recession lasted until mid-2009, making it a longer-than-normal recession, as well as a much deeper recession. Since then, economic growth has been somewhat erratic and the economy has grown slower than in the prior expansions.

Pages 1 and 2 also show the rate of inflation. As reflected in the Consumer Price Index ("CPI"), for example, inflation rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation has declined substantially since 1981. Since 2008, the CPI has been 3 percent or lower, with 2013 being only 1.5 percent and 2014-2015 being below 1 percent. It is thus apparent that the rate of inflation has generally been declining over the past several business cycles. Recent and current levels of inflation are at the lowest levels of the past 35 years, which is reflective of lower capital costs.[3]

Q. What have been the trends in interest rates over the four prior business cycles and at the current time?

A. Pages 3 and 4 of Schedule 2 show several series of interest rates. Both short-term and long-term rates rose sharply to record levels in 1975-1981 when the inflation rate was high. Interest rates have declined substantially in conjunction with inflation since the early 1980s.

[3] The rate of inflation is one component of interest rate expectations of investors, who generally expect to receive a return in excess of the rate of inflation. Thus, a lower rate of inflation has a downward impact on interest rates and other capital costs.

From 2008 to late 2015, the Federal Reserve System ("Federal Reserve") maintained the Federal Funds rate (i.e., short-term interest rate) at 0.25 percent, an all-time low. The Federal Reserve raised it slightly to 0.50 percent in December of 2015. The Federal Reserve also purchased U.S. Treasury securities to stimulate the economy.[4] As seen on page 4 of Schedule 2, both U.S. and corporate bond yields have declined to their lowest levels in the past four business cycles and in more than 35 years. Even with the 2013-2014 "tapering" and eventual ending of the Federal Reserve's Quantitative Easing program, interest rates have remained low. Currently, both government and corporate lending rates remain at historically low levels, again reflective of lower capital costs.

Q. What does this schedule show for trends of common share prices?

A. Pages 5 and 6 of Schedule 2 show several series of common stock prices and ratios. These indicate that stock prices were essentially stagnant during the high inflation/high interest rate environment of the late 1970s and early 1980s. The 1983-1991 business cycle and the more recent cycles witnessed a significant upward trend in stock prices. The beginning of the recent financial crisis saw stock prices decline precipitously, as stock prices in 2008 and early 2009 were down significantly from peak 2007 levels, reflecting the financial/economic crisis. Beginning in the second quarter of 2009, prices recovered substantially and ultimately reached and exceeded the levels achieved prior to the "crash". On the other hand, recent equity markets have been somewhat volatile.

[4] This is referred to as Quantitative Easing, in which the Federal Reserve initially purchased some $85 billion of U.S. Treasury Securities per month in order to stimulate the economy. The Federal Reserve eventually "tapered" its purchase of U.S. Treasury securities through October 2014, at which time Quantitative Easing ended.

Q. What conclusions do you draw from your discussion of economic and financial conditions?

A. Recent economic and financial circumstances have differed from any that have prevailed since at least the 1930s. The late 2008-early 2009 deterioration in stock prices, the decline in U.S. Treasury bond yields, and an increase in corporate bond yields were evidenced in the then-evident "flight to safety." Concurrently, there was a decline in capital costs and returns, which significantly reduced the value of most retirement accounts, investment portfolios and other assets. One significant aspect of this has been a decline in investor expectations of returns,[5] even with the return of stock prices to levels achieved prior to the "crash". This is evident in several ways: 1) lower interest rates on bank deposits; 2) lower interest rates on U.S. Treasury and corporate bonds; 3) lower increases in Social Security cost of living benefits;[6] and 4) lower authorized ROEs by regulatory commissions. Finally, as noted above, utility bond interest rates are currently at levels below those prevailing prior to the financial crisis of late 2008 to early 2009 and are near the lowest levels in the past 35 years.

Q. How do these economic/financial conditions impact the determination of a ROE for regulated utilities?

A. The COC for regulated utilities has declined in recent years. For example, the current interest costs that utilities pay on new debt remain near the low point of the last several decades. In addition, the results of the traditional ROE models (i.e., DCF, CAPM and CE) are lower than was the case prior to the Great Recession. In light of this, it is not surprising that the average ROE authorized by state regulatory agencies have declined and continue to decline through 2015, as follows:

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[5] *See*, for example, Kiplinger's Personal Finance, "Investors Brace for Smaller Gains, Focus on Long-Term," August 30, 2015.

[6] The 2015 increase in Social Security benefits was 1.70 percent – near an all-time record. There is no increase in 2016 Social Security benefits.

Year	Electric[7]	Natural Gas
2012	10.01%	9.94%
2013	9.94%	9.68%
2014	9.76%	9.78%
2015	9.58%	9.60%

TEP'S OPERATIONS AND RISKS

Q. Please describe TEP.

A. TEP, the applicant in this proceeding, serves approximately 414,000 customers in the Tucson metropolitan area of Arizona. TEP, and its sister company (UniSource Energy Services which owns UNS Electric and UNS Gas) are subsidiaries of UNS Energy. UNS Energy, and all of its utility subsidiaries, were acquired by Fortis in August of 2014.

Q. Please describe Fortis, Inc.

A. Fortis is the largest investor-owned electric and gas distribution utility in Canada. Fortis owns several U.S. and Canadian utilities:

- UNS Energy
- Central Hudson Gas & Electric
- Fortis BC
- Fortis Alberta
- Eastern Canada Electric Utilities
  - Newfoundland Power
  - Maritime Electric
  - Fortis Ontario
- Caribbean Utilities

[7] Average ROE values for electric utilities exclude Virginia surcharge/rider generation cases that incorporate plan-specific ROE premiums. *See* Regulatory Research Associates, Regulatory Focus, January 14, 2016, page 1.

Fortis also owns non-regulated hydroelectric generation assets in Canada, Belize and upstate New York.

Q. What are the current security ratings of TEP?

A. TEP's current security ratings are as follows:

Moody's	A3
Standard & Poor's	BBB+

(Source: Response to STF 15-11).

Q. What has been the trends of TEP's security ratings?

A. This is shown on Schedule 3. As this indicates, TEP's security ratings have increased twice, by both Moody's and S&P, since 2011.

Q. Were there any financial integrity implications for TEP as a result of the Fortis acquisition?

A. Yes, there were. On October 28, 2014, Standard & Poor's raised TEP's ratings to BBB+ from BBB. S&P noted:

> "The upgrade reflects our view that parent UNS Energy Corp. (UNS) is a 'moderately strategic' subsidiary of Fortis and therefore subsidiary Tucson Electric Power Co.'s (TEP) issuer credit rating can be raised one notice, while its ratings remain one notch below Fortis issuer credit rating"
>
> . . .
>
> "We could downgrade TEP if parent Fortis is downgraded."

This indicates that, although TEP's securities were upgraded as a result of the Fortis acquisition, its ratings remain tied to those of Fortis.

Q. Have there been any recent developments that relate to this relationship?

A. Yes. On February 10, 2016, S&P placed TEP's security ratings "outlook" on "negative". S&P stated:

> Tucson Electric Power Co.'s ultimate parent Fortis Inc. announced its planned acquisition of utility holding company ITC Holding Corp. and on Feb. 9, 2016, we revised the outlook on Fortis to negative from stable. We maintain our view of Tucson Electric as a moderately strategic subsidiary of Fortis.
>
> We are affirming the ratings on Tucson Electric, including the 'BBB+' issuer credit rating and 'BBB+' senior unsecured debt rating, and revising the outlook to negative from stable.
>
> The negative outlook reflects the possibility that we could downgrade Fortis by up to one notch on its ITC acquisition. This reflects execution and integration risks, as well as the probability that consolidated financial measures could weaken because of increased consolidated debt from the acquisition's financing.

Q. Do the above actions by Standard & Poor's have any relevance to the "conditions" agreed to by Fortis in connection with the acquisition of UniSource and TEP?

A. There are potentially some implications of the possible downgrades of Fortis and TEP securities in connection with the proposed acquisition of the ITC Holdings Corp.

Q. Please explain why this is the case.

A. It is my understanding that, in connection with the acquisition of UniSource (and TEP) by Fortis, one of the "conditions" agreed to by the parties was that no future acquisition by Fortis would have a material adverse impact on UniSource (and by implication TEP). This was cited as "Condition 10" in Attachment A of the Settlement Agreement that was approved by the Commission in Decision No. 74689.

As cited above in the S&P report, the pending acquisition of ITC Holdings by Fortis has resulted in both Fortis and TEP being placed on "negative" credit-watch with the potential for a downgrade. I note that no downgrade has occurred as of this time. Should a downgrade occur, there may be some relevant implications of the "Condition 10".

Should a downgrade to TEP's securities occur in the future, as the result of Fortis' acquisition of ITC Holdings or any other entity, the Staff should reserve the right to comment on whether this would result in a material adverse impact.

CAPITAL STRUCTURE AND COST OF DEBT

Q. What is the importance of determining a proper capital structure in a regulatory framework?

A. A utility's capital structure is important because the concept of rate base – rate of return regulation requires the capital structure to be utilized in estimating the total COC. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities.

As discussed in Section III of my testimony, the purpose of determining the proper capital structure for a utility is to ascertain its capital costs. The rate base – rate of return concept recognizes the assets employed in providing utility services and provides for a return on these assets by identifying the liabilities and common equity (and their cost rates) used to finance the assets. In this process, the rate base is derived from the asset side of the balance sheet and the COC is derived from the liabilities/owners' equity side of the balance sheet. The inherent assumption in this procedure is that the dollar values of the capital structure and the rate base are approximately equal and the former is utilized to finance the latter.

The common equity ratio (i.e. the percentage of common equity in the capital structure) is the capital structure item which normally receives the most attention. This is the case because common equity: (1) usually commands the highest cost rate; (2) generates associated income tax liabilities; and (3) causes the most controversy since its cost cannot be precisely determined.

Q. What are the historic capital structure ratios of TEP?

A. I have examined the historic (2011-2015) capital structure ratios of TEP. See Schedule 4, page 1. TEP's common equity ratios have been:

	Equity	Debt
2011	35.2%	64.8%
2012	35.3%	64.7%
2013	37.6%	62.4%
2014	41.8%	58.2%
2015	49.2%	50.8%

It is apparent that TEP has substantially increased its equity ratio over the past five years.

Page 2 of Schedule 4 shows the capital structure ratios of Fortis over this same period:

	Equity	Debt/Preferred
2011	34.7%	65.3%
2012	35.0%	65.0%
2013	34.8%	65.2%
2014	34.4%	65.6%
2015	36.8%	64.2%

These equity ratios are somewhat lower than those of TEP.

Q. How do these capital structures compare to those of investor-owned electric utilities?

A. Schedule 5 shows the common equity ratios (including short-term debt in capitalization) for the groups of electric and combination electric utilities followed by AUS Utility Reports. These are:

Year	Electric	Combination Gas And Electric
2011	47%	46%
2012	47%	46%
2013	48%	47%
2014	47%	47%
2015	47%	47%

(Source: AUS Utility Reports)

These equity ratios are lower than those of TEP.

Q. What capital structure has TEP requested in this proceeding?

A. TEP requests use of its adjusted test year capital structure as of June 30, 2015:

Capital Item	Percent
Long-Term Debt	49.97%
Common Equity	50.03%

The actual test period capital structure is adjusted for the retirement of two sets of bonds.

Q. What capital structure do you propose to use in this proceeding?

A. I have used TEP's actual test year June 30, 2015 capital structure. The Staff's long-standing policy is to rely upon actual test year figures and to not generally incorporate out-of-period adjustments.

Q. Does your proposed capital structure include short-term debt?

A. No, it does not. I normally prefer to include short-term debt in capitalization for COC estimation. However, as Schedule 4 indicates, TEP has not employed short-term debt in recent years.

Q. What is the cost rate of debt in the Company's application?

A. TEP's filing requests a cost of long term debt of 4.32 percent, which is the Company's cost rate at June 30, 2015 (also adjusted for retirements). I use the actual test year June 30, 2015 rate in my COC analyses (4.14 percent).

Q. Can the ROE be determined with the same degree of precision as the cost of debt?

A. No. The cost rates of debt are largely determined by interest payments, issue prices, and related expenses. The ROE, on the other hand, cannot be precisely quantified, primarily because this cost is an opportunity cost. As mentioned previously, there are several models that can be employed to estimate the ROE. Three of the primary methods – DCF, CAPM, and CE – are developed in the following sections of my testimony.

SELECTION OF PROXY GROUPS

Q. How have you estimated the ROE for TEP?

A. TEP is not a publicly-traded company. Consequently, it is not possible to directly apply ROE models to TEP. However, in COC analyses, it is customary to analyze groups of comparison, or "proxy," companies as a substitute for TEP to determine its ROE.

I have accordingly selected two groups for comparison to TEP. I selected one group of electric utilities similar to TEP and UNS Energy (prior to acquisition) using the criteria listed on Schedule 6. These criteria are as follows:

(1) Market cap of $5 billion or less;

(2) Electric revenues 50% or greater;

(3) Common equity ratio 40% or greater;

(4) Value Line Safety rank of 1, 2, or 3;

(5) Standard & Poor's ("S&P") stock ranking of A or B;

(6) S&P and Moody's bond ratings of A or BBB;

(7) Currently pays dividends; and,

(8) Not involved in major merger or acquisition.

In addition, I have conducted studies of the ROE for the electric utilities proxy group that was selected by TEP witness Buckley.

Q. Please explain why you are using two proxy groups in your ROE analyses.

A. It has long been my practice to develop my own independently-determined proxy group and to also conduct ROE analyses on the utility witness' proxy group. My conclusions and recommendation, in turn, are based upon the results of both proxy groups.

DISCOUNTED CASH FLOW ANALYSIS

Q. What are the theory and methodological bases of the DCF model?

A. The DCF model is one of the oldest and most commonly-used models for estimating the ROE for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate (the "constant growth" or "Gordon DCF model"). In this framework, the ROE is derived from the following formula:

$$K = \frac{D}{P} + g$$

where: P = current price

D = current dividend rate

K = discount rate (COC)

g = constant rate of expected growth

This formula essentially recognizes that the return expected or required by investors is comprised of two factors: the dividend yield (current income) and expected growth in dividends (future income).

Q. Please explain how you employ the DCF model.

A. I use the constant growth DCF model. In doing so, I combine the current dividend yield for each of the proxy electric utility stocks described in the previous section with several indicators of expected dividend growth.

Q. How did you derive the dividend yield component of the DCF equation?

A. Several methods can be used to calculate the dividend yield component. These methods generally differ in the manner in which the dividend rate is employed (i.e., current versus future dividends or annual versus quarterly compounding variant). I believe the most appropriate dividend yield component is a quarterly version, which is expressed as follows:

$$Yield - \frac{D_0(1 + 0.5g)}{P_0}$$

This dividend yield component recognizes the timing of dividend payments and dividend increases.

The P_0 in my yield calculation is the average of the high and low stock price for each proxy company for the most recent three month period (February-April 2016). The D_0 is the current annualized dividend rate for each proxy company.

Q. How do you estimate the dividend growth component of the DCF equation?

A. The DCF model's dividend growth rate component is usually the most crucial and controversial element involved in using this methodology. The objective of estimating the dividend growth component is to reflect the growth expected by investors that is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. This is evidenced by the fact that every investment decision resulting in the purchase of a particular stock at a particular price is matched by another investment decision to sell that stock at the same price.

A wide array of indicators exists for estimating investors' growth expectations. As a result, it is evident that investors do not always use one single indicator of growth. It therefore is necessary to consider alternative dividend growth indicators in deriving the growth component of the DCF model. I have considered five indicators of growth in my DCF analyses. These are:

1. Years 2011-2015 (5-year average) earnings retention, or fundamental growth (per Value Line);

2. Five-year average of historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS) (per Value Line);
3. Years 2016, 2017 and 2019-2021 projections of earnings retention growth (per Value Line);
4. Years 2012-2014 to 2019-2021 projections of EPS, DPS, and BVPS (per Value Line); and,
5. Five-year projections of EPS growth (per First Call).

I believe this combination of growth indicators is a representative and appropriate set with which to begin the process of estimating investor expectations of dividend growth for the groups of proxy companies. I also believe that these growth indicators reflect the types of information that investors consider in making their investment decisions. As I indicated previously, investors have an array of information available to them, all of which would be expected to have some impact on their decision-making process.

Q. Please describe your DCF calculations.

A. Schedule 7 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e. prior to adjustment for growth) dividend yield for each proxy company. Pages 2 and 3 show the growth rates for the groups of proxy companies. Page 4 shows the DCF calculations, which are presented on several bases: mean, median, low and high values. These results can be summarized as follows:

	Mean	Median	Mean Low[8]	Mean High[9]	Median Low[9]	Median High[10]
Parcell Proxy Group	8.0%	8.0%	6.9%	9.2%	6.8%	9.0%
Buckley Proxy Group	7.8%	7.7%	6.7%	8.9%	7.0%	8.6%

8 Using only the lowest growth rate.
9 Using only the highest growth rate.

I note that the individual DCF calculations shown on Schedule 7 should not be interpreted to reflect the expected COC for individual companies in the proxy groups; rather, the individual values shown should be interpreted as alternative information considered by investors.

Q. What do you conclude from your DCF analyses?

A. The DCF rates resulting from the analysis of the proxy groups fall within a range between 6.9 percent and 9.2 percent. The highest DCF rates are 8.6 percent to 9.2 percent (8.9 percent mid-point). I believe 9.2 percent represents the current DCF-derived ROE for the proxy groups. I recommend a cost of equity of 9.2 percent for TEP, which focuses on the upper end of the DCF range. I focus on the higher DCF results since recent financial conditions have had the effect of driving many of the DCF results to low levels relative to those of recent years. As such, my recommendation can be viewed as conservative.

CAPITAL ASSET PRICING MODEL ("CAPM") ANALYSIS

Q. Please describe the theory and methodological basis of the CAPM.

A. CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory ("MPT"), which studies the relationships among risk, diversification, and expected returns. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return.

Q. How is the CAPM derived?

A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

where: K = cost of equity

Rf = risk free rate

Rm = return on market

β = beta

R_m-R_f = market risk premium

The CAPM is a variant of the RP method. I believe the CAPM is generally superior to the simple RP method because the CAPM specifically recognizes the risk of a particular company or industry (i.e., beta), whereas the simple RP method assumes the same ROE for all companies exhibiting similar bond ratings or other characteristics.

Q. What value do you use for the risk-free rate?

A. The first input of the CAPM is the risk-free rate (R_f). The risk-free rate reflects the level of return that can be achieved without accepting any risk.

In CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury securities. Two general types of U.S. Treasury securities are often utilized as the R_f component: short-term U.S. Treasury bills and long-term U.S. Treasury bonds.

I have performed CAPM calculations using the three-month average yield (February-April 2016) for 20-year U.S. Treasury bonds. I use the yields on long-term Treasury bonds since this matches the long-term perspective of ROE analyses. Over this three month period, these bonds had an average yield of 2.23 percent.

Q. What is beta and what betas do you employ in your CAPM?

A. Beta is a measure of the relative volatility (and thus risk) of a particular stock in relation to the overall market. Betas less than 1.0 are considered less risky than the market, whereas betas

greater than 1.0 are more risky. Utility stocks traditionally have had betas below 1.0. I utilize the most recent Value Line betas for each company in the proxy groups.

Q. How do you estimate the market risk premium component?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium of common stocks over the risk-free rate, or long-term government bonds. For the purpose of estimating the market risk premium, I considered alternative measures of returns of the S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds (i.e., same timeframe as sources used to develop risk premiums).

First, I compared the actual annual ROEs of the S&P 500 with the actual annual yields of U.S. Treasury bonds. Schedule 8 shows the ROE for the S&P 500 group for the period 1978-2014 (all available years reported by S&P). This schedule also indicates the annual yields on 20-year U.S. Treasury bonds and the annual differentials (i.e. risk premiums) between the S&P 500 and U.S. Treasury 20-year bonds. Based upon these returns, I conclude that the risk premium from this analysis is 6.85 percent.

I next considered the total returns (i.e. dividends/interest plus capital gains/losses) for the S&P 500 group as well as for long-term (i.e., 20-year) government bonds, as tabulated by Morningstar (formerly Ibbotson Associates), using both arithmetic and geometric means. I considered the total returns for the entire 1926-2014 period, which are as follows:

	S&P 500	L-T Gov't Bonds	Risk Premium
Arithmetic	12.1%	6.1%	6.0%
Geometric	10.1%	5.7%	4.4%

I conclude from this analysis that the expected risk premium is about 5.75 percent (i.e. average of all three risk premiums (6.85 percent from Schedule 8; 6.0 percent arithmetic and 4.4 percent geometric from Morningstar). I believe that a combination of arithmetic and geometric means is appropriate since investors have access to both types of means[10] and presumably, both types are reflected in investment decisions and thus, stock prices and the ROE.

Q. What are your CAPM results?

A. Schedule 9 shows my CAPM calculations. The results are:

	Mean	Median
Parcell Proxy Group	6.7%	6.8%
Buckley Proxy Group	6.5%	6.7%

Q. What is your conclusion concerning the CAPM ROE?

A. The CAPM results collectively indicate a ROE of 6.5 percent to 6.8 percent for the group of proxy utilities. I conclude that an appropriate CAPM ROE estimation for TEP is 6.8 percent.

COMPARABLE EARNINGS ANALYSIS

Q. Please describe the basis of the CE methodology.

A. The CE method is derived from the "corresponding risk" concept discussed in the Bluefield and Hope cases. This method is thus based upon the economic concept of opportunity cost. As previously noted, the ROE is an opportunity cost: the prospective return available to investors from alternative investments of similar risk.

[10] For example, Value Line uses compound (i.e., geometric) growth rates in its projection. In addition, mutual funds report growth rates on a compound basis.

The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, it provides a direct measure of the fair return, since it translates into practice the competitive principle upon which regulation rests.

The CE method normally examines the experienced and/or projected return on book common equity. The logic for examining returns on book equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's book common equity to determine the COC. This COC is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base-rate of return methodology used to set utility rates.

Q. How do you apply the CE methodology in your analysis of TEP's ROE?

A. I apply the CE methodology by examining realized ROEs for the groups of proxy electric companies, as well as unregulated companies, and evaluating investor acceptance of these returns by reference to the resulting market-to-book ratios ("M/B"). In this manner it is possible to assess the degree to which a given level of return equates to the COC. It is generally recognized for utilities that M/B of greater than one (i.e. 100 percent) reflects a situation where a company is able to attract new equity capital without dilution (i.e. above book value). As a result, one objective of a fair ROE is the maintenance of stock prices at or above book value. There is no regulatory obligation to set rates designed to maintain a M/B significantly above one.

I further note that my CE analysis is based upon market data (through the use of M/B) and is thus essentially a market test. As a result, my CE analysis is not subject to the criticisms

occasionally made by some who maintain that past ROEs do not represent the COC. In addition, my CE analysis also uses prospective returns and thus is not backward looking.

Q. What time periods do you examine in your CE analysis?

A. My CE analysis first considers the experienced ROEs of the proxy groups of utilities for the period 2002-2015 (i.e. the last fourteen years). The CE analysis requires that I examine a relatively long period of time in order to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is important to examine earnings over a diverse period of time in order to avoid any undue influence from unusual or abnormal conditions that may occur in a single year or shorter period. Therefore, in forming my judgment of the current ROE, I focused on two periods: 2009-2015 (the current business cycle) and 2002-2008 (the most recent business cycle). I have also considered projected ROEs for 2016, 2017 and 2019-2021.

Q. Please describe your CE analysis.

A. Schedules 10 and 11 contain summaries of experienced ROEs for three groups of companies, while Schedule 12 presents a risk comparison of utilities versus unregulated firms.

Schedule 10 shows the ROEs and M/B for the groups of proxy utilities. These can be summarized as follows:

	Parcell Proxy Group	Buckley Proxy Group
Historic ROE		
Mean	8.2-8.6%	8.0-8.8%
Median	8.1-8.4%	8.2-8.6%
Historic M/B		
Mean	126-142%	126-139%
Median	128-136%	128-134%
Prospective ROE		
Mean	8.4-9.2%	8.5-9.3%
Median	8.3-9.0%	8.8-9.3%

These results indicate that historic ROEs of 8.0 percent to 8.8 percent have been adequate to produce M/Bs of 126 percent to 142 percent for the groups of utilities. Furthermore, projected returns on equity for 2016, 2017 and 2019-2021 are within a range of 8.3 percent to 9.3 percent for the utility groups. These relate to 2015 M/Bs of 150 percent or greater.

Q. Do you also review the ROEs of unregulated firms?

A. Yes. As an alternative, I also examine the S&P's 500 Composite group. This is a well-recognized group of firms that is widely utilized in the investment community and is indicative of the competitive sector of the economy. Schedule 11 presents the earned ROEs and M/Bs for the S&P 500 group over the past thirteen years (i.e., 2002-2014). As this schedule indicates, over the two business cycle periods, this group's average ROEs ranged from 12.4 percent to 13.6 percent, with average M/B ranging between 220 percent and 275 percent.

Q. How can the above information be used to estimate TEP's ROE?

A. The recent ROE of the proxy utilities and S&P 500 groups can be viewed as an indication of the level of return realized and expected in the regulated and competitive sectors of the economy. In order to apply these returns to the required ROE for the proxy utilities, however, it is necessary to compare the risk levels of the electric utilities and the competitive

companies. I do this in Schedule 12, which compares several risk indicators for the S&P 500 group and the electric utility groups. The information in Schedule 12 indicates that the S&P 500 group is more risky than the electric utility proxy groups.

Q. What ROE is indicated by your CE analysis?

A. Based on recent ROEs and M/Bs, my CE analysis indicates that the ROE for the proxy utilities is no more than 8.5 percent to 9.5 percent (9.0 percent mid-point). Recent ROEs of 8.0 percent to 8.8 percent have resulted in M/Bs more than 125 percent. Prospective ROEs of 8.3 percent to 9.3 percent have been accompanied by M/Bs over 150 percent. As a result, it is apparent that authorized ROEs below this level would continue to result in M/Bs of well above 100 percent. An ROE return of 9.5 percent should thus result in an M/B well above 100 percent. As I indicated earlier, the fact that M/Bs substantially exceed 100 percent indicates that historic and prospective ROEs of 9.5 percent reflect earning levels that are well above the actual cost of equity for those regulated companies. I also note that a company whose stock sells above book value can attract capital in a way that enhances the book value of existing stockholders, thus creating a favorable environment for financial integrity. Finally, I note that my 8.5 percent to 9.5 percent CE ROE recommendation reflects the actual and prospective ROEs for the electric proxy groups. I have made no adjustments to these return levels to reflect the high level of M/Bs.

RETURN ON EQUITY RECOMMENDATION

Q. Please summarize the results of your three ROE analyses.

A. My three ROE analyses produced the following findings and conclusions:

DCF	9.2%
CAPM	6.8%
CE	9.5%

These results indicate an overall broad range of 6.8 percent to 9.5 percent, which focuses on the top ends of respective individual model results. I recommend a ROE range of 9.2 percent to 9.5 percent for TEP. This range includes my DCF result (9.2 percent), and my CE result (9.5 percent). For the purposes of this proceeding, I recommend the average of these values, which is 9.35 percent.

Q. It appears that your CAPM results are less than your DCF and CE results. Does this imply that the CAPM results should not be considered in determining the ROE for TEP?

A. No. It is apparent that the CAPM results are less than the DCF and CE results. There are two reasons for the lower CAPM results. First, risk premiums are lower currently than was the case in prior years. This is the result of lower equity market returns that have been experienced over the past several years. This is also reflective of a decline in investor expectations of equity returns and risk premiums. Second, the level of interest rates on U.S. Treasury bonds (i.e., the risk free rate) has been lower in recent years. This is partially the result of the actions of the Federal Reserve System to stimulate the economy. This also impacts investor expectations of returns in a negative fashion. I note that, initially, investors may have believed that the decline in Treasury yields was a temporary factor that would soon be replaced by a rise in interest rates. However, this has not been the case as interest rates have remained low and continued to decline for the past five-plus years. As a result, it cannot be maintained that low interest rates (and low CAPM results) are temporary and do not

reflect investor expectations. Consequently, the CAPM results should be considered as one factor in determining the cost of equity for TEP.

TOTAL COST OF CAPITAL

Q. What is the total COC for TEP?

A. Schedule 1 reflects the COC for actual TEP using the test year capital structure and embedded cost of debt, as well as my ROE recommendations. The resulting total COC is a range of 6.60 percent to 6.75 percent with a 6.68 percent midpoint. I recommend a 6.68 percent total COC for TEP.

COMMENTS ON COMPANY TESTIMONY

Q. Have you reviewed the testimony and COC recommendation of TEP witness Ann E. Buckley?

A. Yes, I have. Ms. Buckley is recommending cost of equity for TEP of 10.00 percent to 10.60 percent, with a specific recommendation of 10.35 percent.

Ms. Buckley's 10.35 percent cost of common equity recommendation is derived as follows:

Constant Growth DCF

	Mean Low	Mean	Mean High
30-Day Average Price	8.77%	9.59%	10.36%
90-Day Average Price	8.65%	9.46%	10.23%
180-Day Average Price	8.47%	9.28%	10.03%

Multi-Stage DCF

	Minimum 1st Stage	Average 1st Stage	Maximum 1st Stage
30-Day Average Price	9.56%	9.78%	9.99%
90-Day Average Price	9.43%	9.64%	9.85%
180-Day Average Price	9.24%	9.44%	9.64%

Capital Asset Pricing Model

	Current Risk-Free Rate (3.09%)	2015-2016 Projected Risk-Free Rate (3.57%)	2017-2021 Projected Risk-Free Rate (4.80%)
Bloomberg Beta	10.28%	10.42%	10.80%
Value Line Beta	11.00%	11.12%	11.40%

Bond Yield Plus Risk Premiums

	Current Risk-Free Rate (3.09%)	2015-2016 Projected Risk-Free Rate (3.57%)	2017-2021 Projected Risk-Free Rate (4.80%)
Bond Yield Plus Risk Premium	9.91%	10.12%	10.66%

Q. Do you have any general comments about Ms. Buckley's testimony and conclusions?

A. Yes, I do. Ms. Buckley's testimony over-states the COC for TEP. Each of her methods, and many of the inputs used in her methods, is biased upward in a manner that inflates her return on equity conclusions. In fact, twenty of her twenty-seven ROE measures are below her 10.35 percent recommendation.

Q. What are your disagreements with Ms. Buckley's constant growth DCF analyses?

A. Ms. Buckley's constant growth DCF analyses are based on 30-day, 90-day and 180-day average stock prices for the periods ending July 31, 2015, annualized dividends per share as of July 31, 2015 and the average of Value Line, First Call and Zack's EPS projections. Her DCF analyses are applied to her group of twelve electric utilities.

Even though Ms. Buckley purports to examine three alternative growth rates in her constant growth DCF analyses, in reality each of the three focuses on a single statistic: analysts' forecasts of EPS. As a result, all of Ms. Buckley's constant growth rates focus exclusively on EPS forecasts and exclude everything else.

Q. Why is it improper to rely exclusively on EPS forecasts in a DCF analysis?

A. There are several reasons why it is not appropriate to rely exclusively on analysts' forecasts in a DCF context. First, it is not realistic to believe that investors rely exclusively on a single factor, such as analysts' forecasts, in making their investment decisions. Investors have an abundance of available information to assist them in evaluating stocks; EPS forecasts are only one of many such statistics.

Second, Value Line – one of Ms. Buckley's sources of EPS projections – publishes both historic and forecasted data, as well as ratios, for a large number of publicly-traded companies. Presumably, both types of information are published for the consideration of its subscribers/investors. Yet, Ms. Buckley considers only *one* factor – the *forecast* version of EPS in her analyses.

Third, the vast majority of information available to investors, by both individual companies in the form of annual reports and offering circulars, and by investment publications such as

Value Line, is historic data. It is neither realistic nor logical to maintain that investors only consider projected (estimated) data for a single statistic (EPS) to the exclusion of historic (actual) data and other statistics (historic and estimated).

Fourth, the experience over the past several years should be a clear signal to investors that analysts cannot accurately predict EPS levels. Few, if any, analysts predicted the decline in security prices in the tech market crash of 2000-2002, as well as the financial crisis of 1998-2009.[11] Thus, relying only on forecasted EPS levels, while ignoring historic EPS levels, cannot and will not produce accurate results.

In summary, investors are now very much aware of recent inabilities of security analysts to accurately predict EPS growth. These problems clearly call into question the reliance on analysts' forecasts as the *only* source of growth in a DCF context. As a result, the landscape has changed in recent years and investors have ample reasons to doubt the reliability of such forecasts at the present time. In light of the above, it is problematic to rely exclusively on such forecasts in determining the cost of equity for TEP.

Q. Are you aware of any recent analyses and comments on the accuracy of analysts' forecasts?

A. Yes, I am. A 2010 study by McKinsey & Company, titled, "Equity Analysts: Still Too Bullish" concludes that "after almost a decade of stricter regulation, analysts' earnings forecasts continue to be excessively optimistic." I have attached a copy of this study as Schedule 13. The significance of this study, as well as the points I raised previously, is that investors should be hesitant to rely exclusively on analysts' forecasts in making investment decisions.

[11] As demonstration of this, see "Security Analysts and their Recommendations," (http://thismatter.com/money/stocks/valuation/security-analysts.htm).

Q. Has the United States Securities and Exchange Commission issued any reports that address the exclusive reliance on analysts' recommendations?

A. Yes. In a 2010 "Investor Alert: Analyzing Analyst Recommendations" the Securities and Exchange Commission ("SEC") made the following statement:

> As a general matter, investors should not rely solely on an analyst's recommendation when deciding whether to buy, hold, or sell a stock. Instead, they should also do their own research – such as reading the prospectus for new companies or for public companies, the quarterly and annual reports filed with the SEC – to confirm whether a particular investment is appropriate for them in light of their individual financial circumstances.

The SEC "Investor Alert" (attached as Schedule 14) also cites the potential conflicts of interest that analysts face.

This "Investor Alert" thus also calls into question the exclusive reliance on analysts' forecasts, as proposed by Ms. Buckley.

Q. Please now turn to Ms. Buckley's second DCF analysis.

A. Ms. Buckley's second DCF model, which is a multi-stage DCF analysis, also relies exclusively on EPS projections as the short-term growth rate. As such, it is subject to the same over-statements as her constant growth DCF. In addition, her long-term growth rate relies on the 5.40 percent GDP projections as the DCF growth rate. As such, it also results in an over-statement of the DCF cost of equity.

Q. What is the source of this 5.40 percent GDP figure?

A. According to Ms. Buckley's testimony on page 28, this 5.40 percent GDP growth is based on the historic growth of GDP from 1929-2014, plus a projected inflation rate.

Q. Is there anything inconsistent with Ms. Buckley's use of historic GDP growth in her DCF analyses?

A. Yes, there is. All of Ms. Buckley's growth rates in her constant growth DCF analyses and the short-term growth rate in her multi-stage DCF analysis (i.e., EPS growth) reflect only projections of future growth. On the other hand, Ms. Buckley only uses historic GDP rates in her GDP growth input. Apparently, Ms. Buckley believes it is not proper to use historic growth rates of financial indicators (i.e., EPS growth), but it is proper to use only historic growth rates in her GDP input.

Q. Are you aware of any projections of GDP growth?

A. Yes, I am. There are at least two commonly-recognized sources of projections of GDP growth. These are:

- Social Security Administration ("SSA"), and
- Energy Information Administration ("EIA").

The two organizations cited above are U.S. government-sponsored organizations.

Q. What are the projections of GDP growth by these two organizations?

A. The projections of GDP growth by these two organizations are:

SSA – 2010-2085 – 4.6% (see Schedule 15)

EIA – 2008-2035 – 4.4% (see Schedule 15)

Each of these projections is about 100 basis points below the 5.40 percent GDP figure used by Ms. Buckley.

Q. Would it be more appropriate to use historic or projected growth rates of GDP in a DCF analysis such as that being used by Ms. Buckley?

A. It would be appropriate to use projections of GDP growth, since Ms. Buckley is using projections of the other growth rate indicators.

Q. Is it reasonable to believe that investors would expect GDP growth to be 5.40 percent, in spite of much lower projections by the U.S. government forecasting organizations?

A. No, it is not. It would be expected that the government's forecasts of GDP would be considered by investors as the most unbiased and reliable estimate.

Q. Are you aware of any utility regulatory agencies that utilize GDP growth as a component in a DCF analysis?

A. The only regulatory agency of which I am aware that directly and formally uses GDP growth in a DCF context is the Federal Energy Regulatory Commission ("FERC"). The FERC uses a two-stage DCF model in establishing the cost of equity for electric utilities and interstate natural gas pipelines. The first stage of the FERC two-stage DCF model is 5-year EPS forecasts, while the second stage is GDP projections for 6-25+ years into the future.

Q. How much weight does FERC give the GDP growth rate in its two-stage DCF model?

A. Thirty-three percent.

Q. Are you aware of any regulatory agencies that use historic GDP growth in a DCF context?

A. No, not in the same context as Ms. Buckley does.

Q. Do you agree with Ms. Buckley's CAPM methodology and conclusions?

A. No, I do not. I specifically disagree with her use of projected interest rates as the risk-free rate and her risk premium factor.

Q. Why is it not proper to use projected interest rates as the risk-free rate?

A. It is proper to use the current (i.e., actual) yield as the risk-free rate in a CAPM context. This is the case since the current yield is known and measurable and reflects investors' collective assessment of all capital market conditions. Prospective interest rates, in contrast, are not measurable and not achievable. For example, if the current yield on 20-year U.S. Treasury Bonds is about 2.5 percent, this reflects the rate that investors can actually receive on their investment. Investors cannot receive a prospective yield on their investments since such a yield is not actual but rather speculative.

Use of the current risk-free rate in a CAPM context is similar to using the current yield in a DCF context. Analysts do not use prospective stock prices as the basis for the dividend yield in a DCF analysis, as use of prospective stock prices is speculative. Use of current stock prices is appropriate, as are used by Ms. Buckley. Likewise, current levels of interest rates reflect all current information (i.e., the efficient market hypothesis) and should be used as the risk-free rate in the CAPM.

Q. Do you agree with Ms. Buckley's risk premium component of the CAPM?

A. No. Ms. Buckley's CAPM analysis utilizes a risk premium that is based on the "expected return on the S&P 500 Index" using a constant growth DCF analysis (13.41 percent) and three measures of the risk-free rate (two of which are projections of interest rates). She thus derives three risk premium values:

Current interest rate (3.09%)	10.33%
Short-Term projected interest rate (3.57%)	9.85%
Longer-Term projected interest rate (4.80%)	8.61%

Each of these greatly exceeds the long-term experience (e.g., 1926 to present) of investment return differential between common stocks and government bonds, as I described earlier in my testimony. Over this period, risk premiums have averaged less than 6 percent. Ms. Buckley offered no evidence or rationale to explain why investors would expect such a large increase in risk premiums over historic levels. Again, Ms. Buckley chooses data that produce higher and excessive results.

Q. Do you have any responses to Ms. Buckley's risk premium analyses?

A. Yes. Ms. Buckley's risk premium approach compares the allowed ROEs for electric utilities and 30-Year U.S. Government Bond yields over the period 1992 through July 2015. She then performs a regression analysis to develop an expected relationship between 30-year U.S. Government Bond yields and the cost of equity for electric utilities. She applies this regression result to the three levels of 30-year U.S. Treasury Bonds and correspondingly arrives at her 9.91-10.66 percent conclusion. As was the case in her CAPM analyses, two of these three sets of interest rates are projections.

It is apparent from Ms. Buckley's Exhibit AEB-6 that the preponderance of decisions since 2005 are well below the 10.50 percent return on equity she is recommending in this proceeding. Not since the third quarter of 2011 has the average ROE award been as high as 10.35 percent.

FAIR VALUE RATE BASE COST OF CAPITAL

Q. What is your understanding of TEP's position on the issue of fair value rate base ("FVRB") and related COC implications?

A. It is my understanding that TEP is requesting that a 5.69 percent COC be applied to the level of its FVRB. This 5.69 percent return incorporates a 1.42 percent cost rate of the "fair value increment" as well as a 10.35 percent ROE.

Q. What is your understanding of the Commission's procedure for utilizing the fair value rate base in setting utility rates?

A. My "non-legal understanding" is that the Commission must consider the fair value of a utility's assets in setting rates. However, I do not agree that this implies that the Company's COC must be applied to the fair value of the rate base.

Q. Are you aware that in 2008 the Commission conducted a "remand" hearing on the issue of regulatory treatment of FVRB for Chaparral City Water Company?

A. Yes, I am. In January of 2008, the Commission conducted a public hearing in response to a remand by the Arizona Appeals Court (Appeals No. CA-CC 05-002) decision[12] in Chaparral City Water Company (Docket No. W-02113A-04-0616). The purpose of this hearing was to determine the appropriate COC to be applied to an Arizona utility's FVRB. The Commission's Decision No. 70441 in that proceeding established a fair value rate of return ("FVROR") by subtracting the inflation rate from the ROE.

Q. What is your understanding of the use of FVRB in Arizona?

A. My "non-legal understanding" is based in part on the 2006 Arizona Court of Appeal in the Chaparral City case that indicates that the Court agreed with the Commission that "the COC

[12] CA-CC 05-002, Memorandum Decision dated February 13, 2007.

analysis' is geared to concepts of original cost measures of rate base, not fair value measures of rate base. . ." The decision goes on to make the following statement: "If the Commission determines that the COC analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology." It is correspondingly the purpose of this section of my testimony to recommend an "appropriate methodology" for use in conjunction with the FVRB.

Q. Do you have any observations based upon your own experience in COC determination, as to whether a COC developed for application to an original cost rate base ("OCRB") is consistent with a FVRB?

A. Yes, I do. It is my personal experience, based upon over 40 years of providing COC testimony, that the concept of COC is designed to apply to an OCRB. This is the case since the COC is derived from the liabilities/owners' equity side of a utility's balance sheet using the book values of the capital structure components. The COC, once determined, is then applied to (i.e., multiplied by) the rate base, which is derived from the asset side of the balance sheet (i.e., OCRB). From a financial perspective, the rationale for this relationship is that the rate base is financed by the capitalization. Under this relationship, a provision is provided for investors (both lenders and owners) to receive a return on their invested capital. Such a relationship is meaningful as long as the COC is applied to the original cost (i.e., book value) rate base, because there is a matching of rate base and capitalization.

When the concept of FVRB is incorporated, however, this link between rate base and capital structure is broken. The amount of FVRB that exceeds OCRB is not financed with investor-supplied funds and, indeed, is not financed at all. As a result, a customary COC analysis cannot be automatically applied to the FVRB since there is no financial link between the two concepts. In my "non-legal" opinion, both the Commission and Appeals Court have also

recognized this lack of compatibility between a customary Weighted COC ("WCOC") analysis and FVRB.

Q. Why is it important that there be a link between the concepts of rate base and COC?

A. This link is important since financial theory indicates that investors should be provided an opportunity to earn a return on the capital they provided to the utility. Since the capital finances the rate base (in an original cost world), the link between COC and rate base satisfies this financial objective.

Q. Based on your experience as a COC witness over the past 40 years, do you have a suggestion as to how to account for the use of a FVRB in setting rates for TEP?

A. Yes, I do. Since the increment between the FVRB and OCRB is not financed with investor-supplied funds, it is logical and appropriate, from a financial standpoint, to assume that this increment has no financing cost. As a result, the COC, through the capital structure, can be modified to account for a level of cost-free capital in an equal dollar amount to the increment of FVRB over the OCRB. Such a procedure would still provide for a return being earned on all investor-supplied funds and would thus be consistent with financial standards.

Q. Have you made such a proposal in this proceeding?

A. Yes, I have. As is shown below, I have developed a capital structure and FVROR that applies to TEP's FVRB.

Item	Percent a/	Cost	Fair Value Return
Long-term Debt	36.94%	4.14%	1.53%
Common Equity	35.05%	9.35%	3.28%
FVRB Increment	28.01%	0.00%	0.00%
Total FVRB Capital	100.00%		4.81%

a/ As developed in Testimony of Commission Staff Witness Mullinax.

Applying this 4.81 percent to the FVRB provides for a return on all investor-supplied capital and is therefore an appropriate rate to apply to the FVRB from a financial and economic standpoint. As such, it provides for an appropriate fair value rate of return to be applied to a FVRB.

Q. Have you developed an alternative method with which to apply a FVROR to a FVRB?

A. Yes, I have. Should the Commission determine that there should be a specific return (greater than zero) applied to the FVRB Increment, I have provided such a procedure.

Q. Why is it necessary to add a return on only the portion of FVRB that exceeds the OCRB?

A. The WCOC authorized by the Commission has already provided for a full cost of equity return and cost of debt on the portions of equity and debt capital that are supporting the OCRB portion of the FVRB. As a result, there is no need to provide any additional return on the portions of FVRB supported by common equity and debt.

Stated differently, both the cost of debt and the return on common equity (i.e., capital stock, paid-in capital, and retained earnings – the investment of common shareholders) are already provided for in a traditional WCOC. Only the portion of the FVRB that exceeds OCRB ("Fair Value Increment" or "FVI") needs to have a specific return identified in order to reflect a return component on that FVI.

Q. What is the proper cost rate to apply to the FVI?

A. As I indicated previously, from a financial perspective, it should not be necessary to provide for any return on the FVI since this is not investor-supplied capital. However, I recognize that the Commission might choose to evaluate this issue from both a financial and a public

policy perspective. I am aware that TEP may claim that the concept of fair value carries with it the notion that investors should receive some benefit when fair value is greater than original cost and should suffer some detriment when fair value is less than original cost. It is possible that the Commission may determine that Arizona's fair value provision, which is somewhat unique, is not inconsistent with these concepts. Nonetheless, the idea that the Company should receive some benefit from the FVI does not mean that one should automatically apply to the FVRB a WCOC developed by reference to OCRB. If it is determined that it is desirable to provide an additional (non-zero) return on the FVI, the proper return should be no larger than the real (i.e., after inflation is removed) risk-free rate of return.

Q. What is the risk-free return?

A. The risk-free return is, in financial terms, the return on an investment that carries little or no risk. Risk-free investments are universally defined as U.S. Treasury Securities, with short-term maturities usually being used as the risk-free rate. Over the past several months, various maturities of U.S. Treasury securities have yielded from about 0.12 percent (short-term) to 3.0 percent (long-term) in nominal terms. I also note that 2016-2017 forecasts of U.S. Treasury securities are about 0.5 percent to 3.7 percent. As a result, I use 3.7 percent as the nominal risk-free rate.

Q. What is the "real" risk-free rate?

A. The concept of real risk-free rates involves the removal of the rate of inflation from the nominal risk-free rate. In 2015, the rate of inflation, as measured by the Consumer Price Index ("CPI"), was 0.7 percent. Forecasts of the CPI for 2016-2017 are about 2.2 percent to 2.5 percent. As a result, I propose to use 2.3 percent inflation rate (the approximate mid-point) for computing the real risk-free rate, which is computed as follows:

Nominal Risk-Free Rate	3.7%
Less: Inflation Rate	2.3%
Equals: Real Risk-Free Rate	1.4%

This 1.4 percent rate essentially matches the 1.42 percent level requested by TEP Witness Buckley.

Q. Please explain why TEP's FVROR should consider the real risk-free rate, as opposed to the nominal risk-free rate.

A. The investors of TEP are already receiving an inflation factor due to the inclusion of inflation in the FVRB Increment. Specifically, the FVI incorporates inflation by considering the current value of assets, which reflect, in part, past inflation. It would be double-counting to also include the inflation components in the return to be applied to the FVI.

Q. What return on the FVI do you recommend in your alternative FVROR proposal?

A. My alternative FVROR proposal incorporates a return on the FVI with a maximum value of 1.4 percent, as developed above. However, I wish to emphasize that this 1.4 percent value is the maximum value that could be applied to the FVRB Increment. In reality, any value between zero percent and 1.4 percent could be used as the cost rate on the FVI. As I stated above, this FVI return is in addition to the return that the Company's investors already earn on their investment in the Company. In this sense, an above-zero cost rate for the FVI represents a bonus to the Company that would have to find its justification in policy considerations instead of in pure economic or financial principles; for that reason, the selection of an appropriate cost rate within this range should fall to the Commission's discretion. I would propose the mid-point of this range, or 0.7 percent.

Q. What is the resulting impact of your alternative proposal in this proceeding?

A. I am proposing the following modified FVROR for TEP:

Capital Item	Percent	Cost	Fair Value Return
Long-term Debt	36.94%	4.14%	1.53%
Common Equity	35.05%	9.35%	3.28%
FVRB Increment	28.01%	0.70%	0.20%
Total	100.00%		5.00%

As shown in the above table, this alternative proposal provides for a non-zero return on the FVI of TEP, and provides for an overall FVROR of 5.00 percent on the FVRB.

Q. What is your understanding of how the two FVROR options you have developed will be used in the development of Staff's revenue requirement recommendations?

A. As I indicated above, I have developed two FVROR calculations – Option 1 that includes a zero percent return on the FVRB increment (4.81 percent FVROR) and Option 2 that includes a 0.70 percent return on the FVRB increment (5.00 percent FVROR). The Staff revenue requirement, as developed in the Direct Testimony of Ms. Mullinax, calculates FVROR based on the second option. The FVROR for Option 2 is 5.00 percent, which matches the mid-point of my ROE range and my specific ROE recommendation.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

2007-Present	President, Technical Associates, Inc.
1995-2007	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATIONS

Certified Rate of Return Analyst - Founding Member

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies. Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

Utility Economics -- Performed numerous financial studies of regulated public utilities. Testified in over 500 cases before some fifty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Mississippi, Missouri, Nebraska, Nevada, New Hampshire, New Jersey, New Mexico, North Carolina, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, U.S. Virgin Islands, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Georgia, Mississippi, Missouri, New Hampshire, North Carolina, Ontario (Canada), South Carolina, U.S. Virgin Islands and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Jersey, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, Old Dominion Electric Cooperative, and industrial customers.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, Massachusetts, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.
Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.
Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information

concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts

Board of Directors	1992-2000
Secretary/Treasurer	1994-1998
President	1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

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Exhibit DCP-1
Schedule 1

TUCSON ELECTRIC POWER COMPANY
TOTAL COST OF CAPITAL

Item	Amount 1/	Percent	Cost	Weighted Cost
Short-Term Debt	$0	0.00%	n/a	0.00%
Long-Term Debt	$1,521,156	51.31%	4.14% 1/	2.12%
Common Equity	$1,443,610	48.69%	9.20% 9.35% 9.50%	4.48% 4.55% 4.63%
Total	$2,964,766	100.00%		6.60% 6.75% 6.68%

1/ Actual Test Year June 30, 2015 amounts and percents as contained in Company filing, Schedule D-1.

ECONOMIC INDICATORS

Year	Real GDP* Growth	Industrial Production Growth	Unemployment Rate	Consumer Price Index
		1975 - 1982 Cycle		
1975	-1.1%	-8.9%	8.5%	7.0%
1976	5.4%	10.8%	7.7%	4.8%
1977	5.5%	5.9%	7.0%	6.8%
1978	5.0%	5.7%	6.0%	9.0%
1979	2.8%	4.4%	5.8%	13.3%
1980	-0.2%	-1.9%	7.0%	12.4%
1981	1.8%	1.9%	7.5%	8.9%
1982	-2.1%	-4.4%	9.5%	3.8%
		1983 - 1991 Cycle		
1983	4.0%	3.7%	9.5%	3.8%
1984	6.8%	9.3%	7.5%	3.9%
1985	3.7%	1.7%	7.2%	3.8%
1986	3.1%	0.9%	7.0%	1.1%
1987	2.9%	4.9%	6.2%	4.4%
1988	3.8%	4.5%	5.5%	4.4%
1989	3.5%	1.8%	5.3%	4.6%
1990	1.8%	-0.2%	5.6%	6.1%
1991	-0.5%	-2.0%	6.8%	3.1%
		1992 - 2001 Cycle		
1992	3.0%	3.1%	7.5%	2.9%
1993	2.7%	3.4%	6.9%	2.7%
1994	4.0%	5.5%	6.1%	2.7%
1995	3.7%	4.8%	5.6%	2.5%
1996	4.5%	4.3%	5.4%	3.3%
1997	4.5%	7.3%	4.9%	1.7%
1998	4.2%	5.8%	4.5%	1.6%
1999	3.7%	4.5%	4.2%	2.7%
2000	4.1%	4.0%	4.0%	3.4%
2001	1.1%	-3.4%	4.7%	1.6%
		2002 - 2009 Cycle		
2002	1.8%	0.2%	5.8%	2.4%
2003	2.8%	1.2%	6.0%	1.9%
2004	3.8%	2.3%	5.5%	3.3%
2005	3.3%	3.2%	5.1%	3.4%
2006	2.7%	2.2%	4.6%	2.5%
2007	1.8%	2.5%	4.6%	4.1%
2008	-0.3%	-3.4%	5.8%	0.1%
2009	-2.8%	-11.3%	9.3%	2.7%
		Current Cycle		
2010	2.5%	5.6%	9.6%	1.5%
2011	1.6%	3.0%	8.9%	3.0%
2012	2.2%	2.8%	8.1%	1.7%
2013	1.5%	1.9%	7.4%	1.5%
2014	2.4%	2.9%	6.2%	0.8%
2015	2.4%	0.3%	5.3%	0.7%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues

ECONOMIC INDICATORS

Year	Real GDP* Growth	Industrial Production Growth	Unemployment Rate	Consumer Price Index
2002				
1st Qtr.	2.7%	-3.6%	5.6%	2.8%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%
4th Qtr.	0.2%	1.4%	5.9%	1.6%
2003				
1st Qtr.	1.2%	1.1%	5.8%	4.8%
2nd Qtr.	3.6%	-0.8%	6.2%	0.0%
3rd Qtr.	7.5%	-0.9%	6.1%	3.2%
4th Qtr.	2.7%	1.5%	5.9%	-0.3%
2004				
1st Qtr.	3.0%	2.8%	5.6%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%
3rd Qtr.	3.8%	4.6%	5.4%	0.8%
4th Qtr.	2.5%	4.3%	5.4%	3.6%
2005				
1st Qtr.	4.1%	3.8%	5.3%	4.4%
2nd Qtr.	1.7%	3.0%	5.1%	1.6%
3rd Qtr.	3.1%	2.7%	5.0%	8.8%
4th Qtr.	2.1%	2.9%	4.9%	-2.0%
2006				
1st Qtr.	5.4%	3.4%	4.7%	4.8%
2nd Qtr.	1.4%	4.5%	4.8%	4.8%
3rd Qtr.	0.1%	5.2%	4.7%	0.4%
4th Qtr.	3.0%	3.5%	4.5%	0.0%
2007				
1st Qtr.	0.9%	2.5%	4.5%	4.8%
2nd Qtr.	3.2%	1.6%	4.5%	5.2%
3rd Qtr.	2.3%	1.8%	4.6%	1.2%
4th Qtr.	2.9%	1.7%	4.8%	6.4%
2008				
1st Qtr.	-1.8%	1.9%	4.9%	2.8%
2nd Qtr.	1.3%	0.2%	5.3%	7.8%
3rd Qtr.	-3.7%	-3.0%	6.0%	2.8%
4th Qtr.	-8.9%	6.0%	6.9%	-13.2%
2009				
1st Qtr.	-5.3%	-11.6%	8.1%	2.4%
2nd Qtr.	-0.3%	-12.9%	9.3%	3.2%
3rd Qtr.	1.4%	-9.3%	9.8%	2.0%
4th Qtr.	4.0%	-4.5%	10.0%	2.5%
2010				
1st Qtr.	1.6%	2.7%	9.7%	0.9%
2nd Qtr.	3.9%	6.5%	9.7%	-1.2%
3rd Qtr.	2.8%	6.9%	9.6%	2.8%
4th Qtr.	2.8%	6.2%	9.6%	2.8%
2011				
1st Qtr.	-1.5%	5.4%	9.0%	4.8%
2nd Qtr.	2.9%	3.6%	9.0%	3.2%
3rd Qtr.	0.8%	3.3%	9.1%	2.4%
4th Qtr.	4.6%	4.0%	8.7%	0.4%
2012				
1st Qtr.	2.3%	4.5%	8.3%	3.2%
2nd Qtr.	1.6%	4.7%	8.2%	0.0%
3rd Qtr.	2.5%	3.4%	8.1%	4.0%
4th Qtr.	0.1%	2.8%	7.8%	0.0%
2013				
1st Qtr.	1.9%	2.5%	7.7%	2.0%
2nd Qtr.	1.1%	2.0%	7.6%	1.2%
3rd Qtr.	3.0%	2.8%	7.3%	1.6%
4th Qtr.	3.9%	3.3%	7.0%	1.2%
2014				
1st Qtr.	-0.9%	3.2%	6.6%	1.6%
2nd Qtr.	4.6%	4.2%	6.2%	3.6%
3rd Qtr.	4.3%	4.7%	6.1%	0.0%
4th Qtr.	2.1%	4.5%	5.7%	-2.8%
2015				
1st Qtr.	0.6%	3.5%	5.6%	-1.2%
2nd Qtr.	3.9%	0.4%	5.4%	3.2%
3rd Qtr.	2.0%	0.1%	5.2%	-0.1%
4th Qtr.	1.4%	-1.6%	5.0%	0.0%
2016				
1st Qtr.	0.5%	-1.7%	4.9%	-0.4%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

Year	Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aaa	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.44%	5.02%	7.47%	7.59%	7.78%	8.02%
			2002 - 2009 Cycle				
2002	4.67%	1.62%	4.61%	[1]	7.19%	7.37%	8.02%
2003	4.12%	1.01%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%
2008	5.09%	1.48%	3.66%		6.18%	6.53%	7.25%
2009	3.25%	0.16%	3.26%		5.75%	6.04%	7.06%
			Current Cycle				
2010	3.25%	0.14%	3.22%		5.24%	5.46%	5.96%
2011	3.25%	0.06%	2.78%		4.78%	5.04%	5.57%
2012	3.25%	0.09%	1.80%		3.83%	4.13%	4.86%
2013	3.25%	0.06%	2.35%		4.24%	4.47%	4.98%
2014	3.25%	0.03%	2.54%		4.19%	4.28%	4.80%
2015	3.26%	0.60%	2.14%		4.00%	4.12%	5.03%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

	Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
2010						
Jan	3.25%	0.08%	3.73%	5.55%	5.77%	6.16%
Feb	3.25%	0.10%	3.69%	5.60%	5.87%	6.25%
Mar	3.25%	0.15%	3.73%	5.64%	5.84%	6.22%
Apr	3.25%	0.15%	3.85%	5.62%	5.81%	6.19%
May	3.25%	0.16%	3.42%	5.29%	5.50%	5.97%
June	3.25%	0.12%	3.20%	5.22%	5.46%	6.18%
July	3.25%	0.16%	3.01%	4.99%	5.26%	5.98%
Aug	3.25%	0.15%	2.70%	4.76%	5.01%	5.55%
Sept	3.25%	0.15%	2.65%	4.74%	5.01%	5.53%
Oct	3.25%	0.13%	2.54%	4.89%	5.10%	5.62%
Nov	3.25%	0.13%	2.76%	5.12%	5.37%	5.85%
Dec	3.25%	0.16%	3.29%	5.32%	5.56%	6.04%
2011						
Jan	3.25%	0.15%	3.39%	5.29%	5.57%	6.06%
Feb	3.25%	0.14%	3.58%	5.42%	5.68%	6.10%
Mar	3.25%	0.11%	3.41%	5.33%	5.58%	5.97%
Apr	3.25%	0.06%	3.46%	5.32%	5.55%	5.98%
May	3.25%	0.04%	3.17%	5.08%	5.32%	5.74%
June	3.25%	0.04%	3.00%	5.04%	5.26%	5.67%
July	3.25%	0.03%	3.00%	5.06%	5.27%	5.70%
Aug	3.25%	0.05%	2.30%	4.44%	4.89%	5.22%
Sept	3.25%	0.02%	1.98%	4.24%	4.48%	5.11%
Oct	3.25%	0.02%	2.15%	4.21%	4.52%	5.24%
Nov	3.25%	0.01%	2.01%	3.92%	4.25%	4.93%
Dec	3.25%	0.02%	1.98%	4.00%	4.33%	5.07%
2012						
Jan	3.25%	0.02%	1.97%	4.03%	4.34%	5.06%
Feb	3.25%	0.08%	1.97%	4.02%	4.36%	5.02%
Mar	3.25%	0.09%	2.17%	4.16%	4.48%	5.13%
Apr	3.25%	0.08%	2.05%	4.10%	4.40%	5.11%
May	3.25%	0.09%	1.80%	3.92%	4.20%	4.97%
June	3.25%	0.09%	1.62%	3.79%	4.08%	4.91%
July	3.25%	0.10%	1.53%	3.58%	3.93%	4.85%
Aug	3.25%	0.11%	1.68%	3.65%	4.00%	4.88%
Sept	3.25%	0.10%	1.72%	3.69%	4.02%	4.81%
Oct	3.25%	0.10%	1.75%	3.68%	3.91%	4.54%
Nov	3.25%	0.11%	1.65%	3.50%	3.84%	4.42%
Dec	3.25%	0.08%	1.72%	3.75%	4.00%	4.56%
2013						
Jan	3.25%	0.07%	1.91%	3.90%	4.15%	4.66%
Feb	3.25%	0.10%	1.96%	3.95%	4.18%	4.74%
Mar	3.25%	0.09%	1.96%	3.90%	4.15%	4.66%
Apr	3.25%	0.06%	1.76%	3.74%	4.00%	4.49%
May	3.25%	0.05%	1.93%	3.91%	4.17%	4.65%
June	3.25%	0.05%	2.30%	4.27%	4.53%	5.08%
July	3.25%	0.04%	2.58%	4.44%	4.68%	5.21%
Aug	3.25%	0.04%	2.74%	4.53%	4.73%	5.28%
Sept	3.25%	0.02%	2.81%	4.58%	4.80%	5.31%
Oct	3.25%	0.06%	2.62%	4.48%	4.70%	5.17%
Nov	3.25%	0.07%	2.72%	4.56%	4.77%	5.24%
Dec	3.25%	0.07%	2.90%	4.59%	4.81%	5.25%
2014						
Jan	3.25%	0.05%	2.86%	4.44%	4.63%	5.09%
Feb	3.25%	0.06%	2.71%	4.38%	4.53%	5.01%
Mar	3.25%	0.05%	2.72%	4.40%	4.51%	5.00%
Apr	3.25%	0.04%	2.71%	4.30%	4.41%	4.85%
May	3.25%	0.03%	2.56%	4.16%	4.26%	4.89%
June	3.25%	0.03%	2.60%	4.23%	4.29%	4.73%
July	3.25%	0.03%	2.54%	4.16%	4.23%	4.66%
Aug	3.25%	0.03%	2.42%	4.07%	4.13%	4.65%
Sept	3.25%	0.02%	2.53%	4.18%	4.24%	4.76%
Oct	3.25%	0.02%	2.30%	3.96%	4.06%	4.67%
Nov	3.25%	0.02%	2.33%	4.03%	4.09%	4.75%
Dec	3.25%	0.04%	2.21%	3.90%	3.95%	4.70%
2015						
Jan	3.25%	0.03%	1.88%	3.52%	3.58%	4.39%
Feb	3.25%	0.03%	1.99%	3.62%	3.67%	4.44%
Mar	3.25%	0.03%	2.04%	3.67%	3.74%	4.51%
Apr	3.25%	0.02%	1.94%	3.63%	3.76%	4.51%
May	3.25%	0.02%	2.20%	4.05%	4.17%	4.91%
June	3.25%	0.04%	2.36%	4.29%	4.39%	5.13%
July	3.25%	0.03%	2.32%	4.27%	4.40%	5.22%
Aug	3.25%	0.09%	2.17%	4.13%	4.25%	5.23%
Sep	3.25%	0.06%	2.17%	4.25%	4.39%	5.42%
Oct	3.25%	0.01%	2.07%	4.13%	4.29%	5.47%
Nov	3.25%	0.13%	2.26%	4.22%	4.40%	5.57%
Dec	3.50%	0.26%	2.24%	4.18%	4.35%	5.55%
2016						
Jan	3.50%	0.25%	2.09%	4.09%	4.27%	5.49%
Feb	3.50%	0.32%	1.78%	3.94%	4.11%	5.28%
Mar	3.50%	0.32%	1.89%	3.93%	4.16%	5.12%
Apr	3.50%	0.23%	1.81%	3.74%	4.00%	4.75%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

	S&P Composite [1]	NASDAQ Composite [1]	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988	[1]	[1]	2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	$599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	2,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		2002 - 2009 Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2007	1,477.19	2,578.47	13,169.98	1.86%	5.29%
2008	1,220.04	2,161.65	11,252.62	2.37%	3.54%
2009	948.05	1,845.38	8,876.15	2.40%	1.86%
		Current Cycle			
2010	1,139.97	2,349.89	10,662.80	1.98%	6.04%
2011	1,268.89	2,677.44	11,966.36	2.05%	6.77%
2012	1,379.35	2,965.56	12,967.08	2.24%	6.20%
2013	1,462.51	3,537.69	14,999.67	2.14%	5.57%
2014	1,930.67	4,374.31	16,773.99	2.04%	5.25%
2015	2,061.20	4,943.49	17,590.81	2.10%	4.59%

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

STOCK PRICE INDICATORS

	S&P Composite	NASDAQ Composite	DJIA	S&P D/P	S&P E/P
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
4th Qtr.	1,262.07	2,246.09	10,827.79	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	4.51%
2008					
1st Qtr.	1,350.19	2,332.91	12,383.86	2.11%	4.55%
2nd Qtr.	1,371.65	2,426.26	12,508.59	2.10%	4.05%
3rd Qtr.	1,251.94	2,290.87	11,322.40	2.29%	3.94%
4th Qtr.	909.80	1,599.64	8,795.61	2.98%	1.65%
2009					
1st Qtr.	809.31	1,485.14	7,774.06	3.00%	0.86%
2nd Qtr.	892.23	1,731.41	8,327.83	2.45%	0.82%
3rd Qtr.	996.68	1,985.25	9,229.93	2.16%	1.19%
4th Qtr.	1,088.70	2,162.33	10,172.78	1.99%	4.57%
2010					
1st Qtr.	1,121.60	2,274.88	10,454.42	1.94%	5.21%
2nd Qtr.	1,135.25	2,343.40	10,570.54	1.97%	6.51%
3rd Qtr.	1,096.39	2,237.97	10,390.24	2.09%	6.30%
4th Qtr.	1,204.00	2,534.62	11,236.02	1.95%	6.15%
2011					
1st Qtr.	1,302.74	2,741.01	12,024.62	1.85%	6.13%
2nd Qtr.	1,319.04	2,766.64	12,370.73	1.97%	6.35%
3rd Qtr.	1,237.12	2,613.11	11,671.47	2.15%	7.69%
4th Qtr.	1,225.65	2,600.91	11,798.65	2.25%	6.91%
2012					
1st Qtr.	1,347.44	2,902.90	12,839.80	2.12%	6.29%
2nd Qtr.	1,350.39	2,928.62	12,765.58	2.30%	6.45%
3rd Qtr.	1,402.21	3,029.86	13,118.72	2.27%	6.00%
4th Qtr.	1,418.21	3,001.69	13,142.91	2.28%	6.07%
2013					
1st Qtr.	1,514.41	3,177.10	14,000.30	2.21%	5.59%
2nd Qtr.	1,609.77	3,369.49	14,961.28	2.15%	5.66%
3rd Qtr.	1,675.31	3,643.63	15,255.25	2.14%	5.61%
4th Qtr.	1,770.45	3,960.54	15,751.98	2.08%	5.42%
2014					
1st Qtr.	1,834.30	4,210.06	16,170.26	2.04%	5.38%
2nd Qtr.	1,900.37	4,195.81	16,803.50	2.08%	5.26%
3rd Qtr.	1,975.95	4,483.51	16,953.85	2.02%	5.37%
4th Qtr.	2,012.04	4,607.86	17,368.36	2.03%	4.97%
2015					
1st Qtr.	2,063.46	4,821.99	17,806.47	2.02%	4.80%
2nd Qtr.	2,094.37	5,029.47	18,007.48	2.05%	4.60%
3rd Qtr.	2,026.14	4,921.81	17,065.52	2.16%	4.72%
4th Qtr.	2,053.17	5,000.70	18,482.97	2.16%	4.23%
2016					
1st Qtr.	1,948.32	4,609.47	16,635.76	2.31%	

Source: Council of Economic Advisors, Economic Indicators, various issues.

Exhibit DCP-1
Schedule 3

TUCSON ELECTRIC POWER COMPANY
AND FORTIS
HISTORY OF CREDIT RATINGS

Year	Tucson Electric Power		Fortis	
	S&P	Moody's	DBRS	Moody's
2011	BBB-	Baa3	BBB/A(low)	A-
2012	BBB-	Baa3	A(low)	A-
2013	BBB-/BBB	Baa3/Baa2	A(low)	A-
2014	BBB/BBB+	Baa2/Baa1	A(low)	A-
2015	BBB+	Baa1/A3	A(low)	A-
2016	BBB+	A3	A(low)	A-/BBB+

Source: Response to STF 15.11.

TUCSON ELECTRIC POWER COMPANY
CAPITAL STRUCTURE RATIOS
2011 - 2015
($000)

YEAR	COMMON EQUITY	LONG-TERM DEBT 1/	SHORT-TERM DEBT
2011	$825,000	$1,510,000	$10,000
	35.2%	64.4%	0.4%
	35.3%	64.7%	
2012	$861,000	$1,576,000	$0
	35.3%	64.7%	0.0%
	35.3%	64.7%	
2013	$926,000	$1,540,000	$0
	37.6%	62.4%	0.0%
	37.6%	62.4%	
2014	$1,216,000	$1,605,000	$85,000
	41.8%	55.2%	2.9%
	43.1%	56.9%	
2015	$1,475,000	$1,521,000	$0
	49.2%	50.8%	0.0%
	49.2%	50.8%	

1/ Includes capital lease obligations.

Note: Percentages may not total 100.0% due to rounding.

Source: Response to STF 19.2.

FORTIS
CAPITAL STRUCTURE RATIOS
2011 - 2015
($millions)

YEAR	COMMON EQUITY	PREFERENCE SHARES	TOTAL DEBT 1/
2011	$3,823	$912	$6,296
	34.7%	8.3%	57.1%
	34.7%	8.3%	57.1%
2012	$3,992	$1,108	$6,317
	35.0%	9.7%	55.3%
	35.0%	9.7%	55.3%
2013	$4,772	$1,229	$7,716
	34.8%	9.0%	56.3%
	34.8%	9.0%	56.3%
2014	$6,871	$1,820	$11,304
	34.4%	9.1%	56.5%
	34.4%	9.1%	56.5%
2015	$8,060	$1,820	$12,022
	36.8%	8.3%	54.9%
	36.8%	8.3%	54.9%

1/ Includes capital lease and finance obligations.

Source: Response to STF 19.2.

Exhibit DCP-1
Schedule 5

AUS UTILITY REPORTS
ELECTRIC UTILITY GROUPS
AVERAGE COMMON EQUITY RATIOS

Year	Electric	Combination Electric and Gas
2011	47%	46%
2012	47%	46%
2013	48%	47%
2014	47%	47%
2015	47%	47%

Note: Averages include short-term debt.

Source: AUS Utility Reports.

Exhibit DCP-1
Schedule 6

PROXY COMPANIES
BASIS FOR SELECTION

Company	Market Capitalization ($ millions)	Percent Reg Electric Revenues	Common Equity Ratio	Value Line Safety	S&P Stock Ranking	S&P Bond Rating	Moody's Bond Rating
UNS Energy 1/	$2,500,000	92%	41%	3	A-	NR	Baa1
Tucson Electric Power			50%			BBB+	A3
Parcell Proxy Group							
ALLETE	$2,700,000	67%	54%	2	A-	A-	A3
Avista Corp	$2,500,000	67%	50%	2	A-	A-	Baa1
El Paso Electric	$1,800,000	100%	47%	2	B	BBB	Baa1
Great Plains Energy	$4,700,000	100%	49%	3	B	BBB	Baa2
IDACORP	$3,700,000	100%	54%	2	A	A-	A3
NorthWestern Corp	$2,900,000	78%	47%	3	A+	NR	A3
Otter Tail Corp	$1,100,000	52%	58%	3	B	BBB-	Baa2
Portland General Corp	$3,500,000	100%	52%	2	NR	A-	A3
PNM Resources	$2,600,000	100%	46%	3	B	BBB	Baa2
Westar Energy	$4,500,000	100%	49%	2	A-	A-	A3/Baa1
Buckley Proxy Group							
ALLETE	$2,700,000	67%	54%	2	A-	A-	A3
American Electric Power	$31,000,000	81%	50%	2	A-	BBB/BBB-	Baa1
Duke Energy Corp	$55,000,000	91%	51%	2	B	BBB+	A3
Empire District Electric	$1,500,000	92%	49%	2	B+	A-	Baa1
Eversource Energy	$18,000,000	88%	54%	1	A-	A-	A3/Baa1
Great Plains Energy Inc.	$4,700,000	100%	49%	3	B	BBB	Baa2
IDACORP, Inc.	$3,700,000	100%	54%	2	A	A-	A3
Otter Tail Corporation	$1,100,000	52%	58%	3	B	BBB-	Baa2
Pinnacle West Capital Corp.	$8,300,000	100%	57%	1	B+	BBB	A3/Baa1
PNM Resources, Inc.	$2,600,000	100%	46%	3	B	BBB	Baa2
Portland General Electric Co.	$3,500,000	100%	52%	2	NR	A-	A3
Westar Energy, Inc.	$4,500,000	100%	49%	2	A-	A-	A3/Baa1

1/ UNS Energy amounts as shown in Value Line reports prior to Fortis acquisition.

Sources: AUS Utility Reports, Value Line.

PROXY COMPANIES
DIVIDEND YIELD

COMPANY	Qtr DPS	February – April 2016 DPS	HIGH	LOW	AVERAGE	YIELD
Parcell Proxy Group						
ALLETE	$0.520	$2.08	$58.34	$50.83	$54.59	3.8%
Avista Corp	$0.343	$1.37	$41.37	$36.72	$39.05	3.5%
El Paso Electric	$0.295	$1.18	$46.63	$39.37	$43.00	2.7%
Great Plains Energy	$0.263	$1.05	$32.74	$27.80	$30.27	3.5%
IDACORP	$0.510	$2.04	$74.99	$68.30	$71.65	2.8%
NorthWestern Corp	$0.500	$2.00	$62.51	$55.49	$59.00	3.4%
Otter Tail Corp	$0.313	$1.25	$29.80	$26.09	$27.95	4.5%
Portland General Corp	$0.300	$1.20	$40.48	$37.04	$38.76	3.1%
PNM Resources	$0.220	$0.88	$34.07	$30.62	$32.35	2.7%
Westar Energy	$0.380	$1.52	$52.82	$41.89	$47.36	3.2%
Average						**3.3%**
Buckley Proxy Group						
ALLETE	$0.520	$2.08	$58.34	$50.83	$54.59	3.8%
American Electric Power	$0.560	$2.24	$67.19	$60.15	$63.67	3.5%
Duke Energy Corp	$0.825	$3.30	$81.39	$72.48	$76.94	4.3%
Empire District Electric	$0.260	$1.04	$33.75	$27.11	$30.43	3.4%
Eversource Energy	$0.445	$1.78	$59.09	$52.62	$55.86	3.2%
Great Plains Energy Inc.	$0.263	$1.05	$32.74	$27.80	$30.27	3.5%
IDACORP, Inc.	$0.510	$2.04	$74.99	$68.30	$71.65	2.8%
Otter Tail Corporation	$0.313	$1.25	$29.80	$26.09	$27.95	4.5%
Pinnacle West Capital Corp.	$0.625	$2.50	$75.81	$66.02	$70.92	3.5%
PNM Resources, Inc.	$0.220	$0.88	$34.07	$30.62	$32.35	2.7%
Portland General Electric Co.	$0.300	$1.20	$40.48	$37.04	$38.76	3.1%
Westar Energy, Inc.	$0.380	$1.52	$52.82	$41.89	$47.36	3.2%
Average						**3.5%**

Source: Yahoo! Finance.

PROXY COMPANIES
RETENTION GROWTH RATES

COMPANY	2011	2012	2013	2014	2015	Average	2016	2017	2019-'21	Average
Parcell Proxy Group										
ALLETE	2.9%	2.3%	2.2%	2.5%	3.6%	2.7%	3.0%	3.0%	3.0%	3.0%
Avista Corp	3.1%	0.8%	2.9%	2.4%	2.3%	2.3%	2.5%	2.5%	3.5%	2.8%
El Paso Electric	10.0%	6.3%	4.9%	4.8%	3.4%	5.9%	3.5%	3.5%	3.0%	3.3%
Great Plains Energy	2.0%	2.2%	3.2%	2.7%	1.6%	2.3%	3.0%	3.0%	3.0%	3.0%
IDACORP	6.5%	5.7%	5.6%	5.4%	4.8%	5.6%	4.5%	4.0%	3.5%	4.0%
NorthWestern Corp	4.7%	3.2%	3.5%	3.8%	3.0%	3.6%	3.0%	4.0%	4.0%	3.7%
Otter Tail Corp	0.0%	0.0%	1.2%	2.2%	2.0%	1.1%	2.0%	2.0%	4.0%	2.7%
Portland General Corp	4.1%	3.5%	2.9%	4.6%	3.5%	3.7%	4.0%	4.0%	4.0%	4.0%
PNM Resources	3.3%	3.8%	3.7%	3.2%	4.0%	3.6%	3.5%	3.5%	3.5%	3.5%
Westar Energy	2.7%	4.0%	4.2%	4.3%	2.9%	3.6%	4.5%	4.5%	5.0%	4.7%
Average						3.4%				3.5%
Buckley Proxy Group										
ALLETE	2.9%	2.3%	2.2%	2.5%	3.6%	2.7%	3.0%	3.0%	3.0%	3.0%
American Electric Power	4.2%	3.5%	3.7%	3.8%	4.0%	3.8%	4.0%	3.5%	3.5%	3.7%
Duke Energy Corp	2.2%	0.9%	1.5%	1.7%	1.5%	1.6%	2.0%	2.0%	2.0%	2.0%
Empire District Electric	4.1%	1.9%	2.7%	2.9%	1.5%	2.6%	1.5%	2.0%	2.5%	2.0%
Eversource Energy	5.0%	1.6%	3.4%	3.5%	3.4%	3.4%	3.5%	3.5%	4.0%	3.7%
Great Plains Energy Inc.	2.0%	2.2%	3.2%	2.7%	1.6%	2.3%	3.0%	3.0%	3.0%	3.0%
IDACORP, Inc.	6.5%	5.7%	5.6%	5.4%	4.8%	5.6%	4.5%	4.0%	3.5%	4.0%
Otter Tail Corporation	0.0%	0.0%	1.2%	2.2%	2.0%	1.1%	2.0%	2.0%	4.0%	2.7%
Pinnacle West Capital Corp.	2.8%	4.1%	4.1%	3.5%	3.9%	3.7%	3.5%	3.5%	3.5%	3.5%
PNM Resources, Inc.	3.3%	3.8%	3.7%	3.2%	4.0%	3.6%	3.5%	3.5%	3.5%	3.5%
Portland General Electric Co.	4.1%	3.5%	2.9%	4.6%	3.5%	3.7%	4.0%	4.0%	4.0%	4.0%
Westar Energy, Inc.	2.7%	4.0%	4.2%	4.3%	2.9%	3.6%	4.5%	4.5%	5.0%	4.7%
Average						3.1%				3.3%

Source: Value Line Investment Survey.

PROXY COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates				Est'd '13-'15 to '19-'21 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Parcell Proxy Group								
ALLETE	5.0%	2.5%	6.0%	4.5%	4.0%	3.5%	3.5%	3.7%
Avista Corp	4.0%	9.0%	4.0%	5.7%	5.0%	4.0%	3.5%	4.2%
El Paso Electric	4.0%		7.5%	5.8%	2.5%	5.0%	3.5%	3.7%
Great Plains Energy	4.0%	-3.0%	2.0%	1.0%	4.5%	5.5%	3.0%	4.3%
IDACORP	8.0%	8.0%	6.0%	7.3%	3.0%	7.5%	4.0%	4.8%
NorthWestern Corp	7.0%	4.5%	7.0%	6.2%	6.5%	5.5%	4.5%	5.5%
Otter Tail Corp	15.5%	0.5%	-3.5%	4.2%	6.0%	1.5%	4.5%	4.0%
Portland General Corp	6.5%	2.5%	3.0%	4.0%	5.5%	6.0%	4.0%	5.2%
PNM Resources	23.5%		1.0%	12.3%	9.0%	10.0%	3.5%	7.5%
Westar Energy	9.0%	3.5%	3.5%	5.3%	6.0%	3.0%	5.0%	4.7%
Average				**5.6%**				**4.8%**
Buckley Proxy Group								
ALLETE	5.0%	2.5%	6.0%	4.5%	4.0%	3.5%	3.5%	3.7%
American Electric Power	1.5%	4.0%	4.5%	3.3%	4.5%	5.0%	4.5%	4.7%
Duke Energy Corp	3.0%	2.5%	3.0%	2.8%	4.0%	3.5%	1.5%	3.0%
Empire District Electric	5.0%	-4.5%	2.0%	0.8%	2.5%	2.5%	2.0%	2.3%
Eversource Energy	6.0%	11.0%	9.0%	8.7%	6.0%	6.0%	4.0%	5.3%
Great Plains Energy Inc.	4.0%		2.0%	3.0%	4.5%	5.5%	3.0%	4.3%
IDACORP, Inc.	8.0%	8.0%	6.0%	7.3%	3.0%	7.5%	4.0%	4.8%
Otter Tail Corporation	15.5%	0.5%	-3.5%	4.2%	6.0%	1.5%	4.5%	4.0%
Pinnacle West Capital Corp.	8.5%	2.0%	3.5%	4.7%	4.0%	5.0%	3.5%	4.2%
PNM Resources, Inc.	23.5%		1.0%	12.3%	9.0%	10.0%	3.5%	7.5%
Portland General Electric Co.	6.5%	2.5%	3.0%	4.0%	5.5%	6.0%	4.0%	5.2%
Westar Energy, Inc.	9.0%	3.5%	3.5%	5.3%	6.0%	3.0%	5.0%	4.7%
Average				**5.1%**				**4.5%**

Source: Value Line Investment Survey.

PROXY COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Parcell Proxy Group								
ALLETE	3.9%	2.7%	3.0%	4.5%	3.7%	3.0%	3.4%	7.2%
Avista Corp	3.6%	2.3%	2.8%	5.7%	4.2%	5.0%	4.0%	7.6%
El Paso Electric	2.8%	5.9%	3.3%	5.8%	3.7%	7.0%	5.1%	7.9%
Great Plains Energy	3.5%	2.3%	3.0%	1.0%	4.3%	7.1%	3.6%	7.1%
IDACORP	2.9%	5.6%	4.0%	7.3%	4.8%	4.0%	5.2%	8.1%
NorthWestern Corp	3.5%	3.6%	3.7%	6.2%	5.5%	5.0%	4.8%	8.3%
Otter Tail Corp	4.6%	1.1%	2.7%	4.2%	4.0%	6.0%	3.6%	8.1%
Portland General Corp	3.2%	3.7%	4.0%	4.0%	5.2%	6.5%	4.7%	7.8%
PNM Resources	2.8%	3.6%	3.5%	12.3%	7.5%	8.8%	7.1%	9.9%
Westar Energy	3.3%	3.6%	4.7%	5.3%	4.7%	5.3%	4.7%	8.0%
Mean	3.4%	3.4%	3.5%	5.6%	4.8%	5.8%	4.6%	**8.0%**
Median	3.4%	3.6%	3.4%	5.5%	4.5%	5.6%	4.7%	**8.0%**
Composite - Mean		**6.9%**	6.9%	9.0%	8.2%	**9.2%**	8.0%	
Composite - Median		**7.0%**	6.8%	8.9%	7.9%	**9.0%**	8.1%	
Buckley Proxy Group								
ALLETE	3.9%	2.7%	3.0%	4.5%	3.7%	3.0%	3.4%	7.2%
American Electric Power	3.6%	3.8%	3.7%	3.3%	4.7%	4.1%	3.9%	7.5%
Duke Energy Corp	4.3%	1.6%	2.0%	2.8%	3.0%	4.6%	2.8%	7.2%
Empire District Electric	3.5%	2.6%	2.0%	0.8%	2.3%	5.0%	2.6%	6.0%
Eversource Energy	3.3%	3.4%	3.7%	8.7%	5.3%	6.0%	5.4%	8.7%
Great Plains Energy Inc.	3.5%	2.3%	3.0%	3.0%	4.3%	7.1%	4.0%	7.5%
IDACORP, Inc.	2.9%	5.6%	4.0%	7.3%	4.8%	4.0%	5.2%	8.1%
Otter Tail Corporation	4.6%	1.1%	2.7%	4.2%	4.0%	6.0%	3.6%	8.1%
Pinnacle West Capital Corp.	3.6%	3.7%	3.5%	4.7%	4.2%	3.6%	3.9%	7.5%
PNM Resources, Inc.	2.8%	3.6%	3.5%	12.3%	7.5%	8.8%	7.1%	9.9%
Portland General Electric Co.	3.2%	3.7%	4.0%	4.0%	5.2%	6.5%	4.7%	7.8%
Westar Energy, Inc.	3.3%	3.6%	4.7%	5.3%	4.7%	5.3%	4.7%	8.0%
Mean	3.5%	3.1%	3.3%	5.1%	4.5%	5.3%	4.3%	**7.8%**
Median	3.5%	3.5%	3.5%	4.3%	4.5%	5.1%	3.9%	**7.7%**
Composite - Mean		**6.7%**	6.8%	8.6%	8.0%	**8.9%**	7.8%	
Composite - Median		**7.0%**	7.0%	7.8%	8.0%	**8.6%**	7.4%	

Note: negative values not used in calculations.

Sources: Prior pages of this schedule.

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND YIELD	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.04	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$18.86	$149.74	12.22%	7.29%	4.93%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$216.51	16.58%	7.60%	8.98%
1996	$38.73	$237.08	17.08%	6.18%	10.90%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.70	$338.37	7.44%	5.53%	1.91%
2002	$27.59	$321.72	8.36%	5.59%	2.77%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
2006	$81.51	$504.39	17.03%	4.68%	12.35%
2007	$66.17	$529.59	12.80%	4.86%	7.94%
2008	$14.88	$451.37	3.03%	4.45%	-1.42%
2009	$50.97	$513.58	10.56%	3.47%	7.09%
2010	$77.35	$579.14	14.16%	4.25%	9.91%
2011	$86.95	$613.14	14.59%	3.81%	10.78%
2012	$86.51	$666.97	13.52%	2.40%	11.12%
2013	$100.20	$715.84	14.49%	2.86%	11.63%
2014	$102.31	$726.96	14.18%	3.33%	10.85%
Average					**6.85%**

Source: Standard & Poor's Analysts' Handbook, Ibbotson Associates Handbook.

Exhibit DCP-1
Schedule 9

PROXY COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	RISK PREMIUM	CAPM RATES
Parcell Proxy Group				
ALLETE	2.23%	0.80	5.75%	6.8%
Avista Corp	2.23%	0.75	5.75%	6.5%
El Paso Electric	2.23%	0.75	5.75%	6.5%
Great Plains Energy	2.23%	0.80	5.75%	6.8%
IDACORP	2.23%	0.80	5.75%	6.8%
NorthWestern Corp	2.23%	0.70	5.75%	6.3%
Otter Tail Corp	2.23%	0.85	5.75%	7.1%
Portland General Corp	2.23%	0.80	5.75%	6.8%
PNM Resources	2.23%	0.80	5.75%	6.8%
Westar Energy	2.23%	0.75	5.75%	6.5%
Mean				**6.7%**
Median				**6.8%**
Buckley Proxy Group				
ALLETE	2.23%	0.80	5.75%	6.8%
American Electric Power	2.23%	0.70	5.75%	6.3%
Duke Energy Corp	2.23%	0.50	5.75%	5.1%
Empire District Electric	2.23%	0.70	5.75%	6.3%
Eversource Energy	2.23%	0.75	5.75%	6.5%
Great Plains Energy Inc.	2.23%	0.80	5.75%	6.8%
IDACORP, Inc.	2.23%	0.80	5.75%	6.8%
Otter Tail Corporation	2.23%	0.85	5.75%	7.1%
Pinnacle West Capital Corp.	2.23%	0.75	5.75%	6.5%
PNM Resources, Inc.	2.23%	0.80	5.75%	6.8%
Portland General Electric Co.	2.23%	0.80	5.75%	6.8%
Westar Energy, Inc.	2.23%	0.75	5.75%	6.5%
Mean				**6.5%**
Median				**6.7%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

20-year Treasury Bonds

Month	Rate
Feb. 2016	2.20%
Mar. 2016	2.28%
Apr. 2016	2.21%
Average	2.23%

PROXY COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2002-2008 Average	2009-2015 Average	2016	2017	2019-21
Parcell Proxy Group																			
ALLETE				12.0%	13.2%	13.4%	11.4%	7.3%	8.2%	9.5%	8.7%	8.4%	8.6%	9.4%		8.6%	8.5%	8.5%	8.5%
Avista Corp	4.5%	6.7%	4.6%	5.8%	8.8%	4.1%	7.6%	8.4%	8.5%	8.6%	6.4%	8.7%	8.1%	7.8%	6.0%	8.1%	8.0%	8.0%	9.0%
El Paso Electric	6.3%	6.5%	6.3%	6.7%	10.5%	11.9%	11.4%	9.4%	11.7%	13.0%	11.4%	10.0%	9.5%	8.2%	8.5%	10.5%	8.0%	8.0%	8.5%
Great Plains Energy	15.6%	16.6%	16.9%	13.7%	9.8%	10.6%	5.9%	4.9%	7.3%	5.8%	6.2%	7.3%	6.8%	5.8%	12.7%	8.3%	7.5%	7.5%	7.5%
IDACORP	7.1%	4.2%	8.2%	7.3%	9.4%	7.1%	8.0%	9.3%	9.8%	10.5%	9.9%	10.1%	10.2%	9.7%	7.3%	9.9%	9.0%	9.0%	9.0%
NorthWestern Corp					6.4%	6.9%	8.4%	9.4%	9.6%	10.9%	9.3%	9.5%	10.3%	9.0%		9.7%	9.0%	10.0%	10.0%
Otter Tail Corp	15.2%	12.0%	10.8%	11.6%	10.4%	10.4%	5.9%	3.7%	2.1%	2.7%	6.9%	9.4%	10.3%	9.9%	10.9%	6.4%	9.0%	9.5%	10.5%
Portland General Corp					5.9%	11.5%	6.5%	6.2%	8.0%	9.0%	8.3%	7.7%	9.1%	8.2%		8.1%	8.0%	9.0%	9.0%
PNM Resources	6.3%	6.7%	7.9%	8.6%	8.4%	3.4%	0.5%	3.1%	4.8%	5.8%	6.6%	6.9%	6.7%	7.6%	6.0%	5.9%	7.5%	8.0%	9.5%
Westar Energy	5.0%	10.6%	7.7%	9.6%	11.1%	10.0%	6.7%	6.3%	8.6%	8.2%	9.5%	9.8%	9.7%	8.2%	8.7%	8.6%	9.0%	10.0%	10.5%
Average	8.6%	9.0%	8.9%	9.4%	9.4%	8.9%	7.2%	6.8%	7.9%	8.4%	8.3%	8.6%	8.9%	8.4%	8.6%	8.2%	8.4%	8.8%	9.2%
Median	6.3%	6.7%	7.9%	9.1%	9.6%	10.2%	7.2%	6.8%	8.4%	8.8%	8.5%	9.1%	9.3%	8.2%	8.1%	8.4%	8.3%	8.8%	9.0%
Buckley Proxy Group																			
ALLETE			0.0%	12.0%	13.2%	13.4%	11.4%	7.3%	8.2%	9.5%	8.7%	8.4%	8.6%	9.4%	10.0%	8.6%	8.5%	8.5%	8.5%
American Electric Power	12.3%	12.4%	12.7%	11.9%	12.2%	11.7%	11.6%	11.0%	9.3%	10.7%	9.7%	9.9%	9.9%	10.2%	12.1%	10.1%	10.0%	10.0%	10.0%
Duke Energy Corp	8.9%	0.6%	8.6%	9.5%	4.8%	6.4%	6.1%	6.8%	8.0%	8.1%	6.8%	6.8%	7.1%	7.1%	6.4%	7.2%	7.5%	8.0%	8.0%
Empire District Electric	8.4%	8.7%	5.7%	6.2%	9.2%	6.9%	7.4%	7.5%	7.4%	8.1%	7.9%	8.6%	8.7%	7.1%	7.5%	7.9%	7.0%	7.5%	9.0%
Eversource Energy	6.4%	7.1%	5.0%	5.4%	4.5%	8.6%	9.8%	9.6%	4.9%	10.0%	7.3%	8.3%	8.3%	8.6%	6.7%	8.1%	9.0%	9.0%	9.5%
Great Plains Energy Inc.	15.6%	16.6%	16.9%	13.7%	9.8%	10.6%	5.9%	4.9%	7.3%	5.8%	6.2%	7.3%	6.8%	5.8%	12.7%	8.3%	7.5%	7.5%	7.5%
IDACORP, Inc.	7.1%	4.2%	8.2%	7.3%	9.4%	7.1%	8.0%	9.3%	9.8%	10.5%	9.9%	10.1%	10.2%	9.7%	7.3%	9.9%	9.0%	9.0%	9.0%
Otter Tail Corporation	15.2%	12.0%	10.8%	11.6%	10.4%	10.4%	5.9%	3.7%	2.1%	2.7%	6.9%	9.4%	10.3%	9.9%	10.9%	6.4%	9.0%	9.5%	10.5%
Pinnacle West Capital Corp.	8.6%	8.3%	8.2%	6.7%	9.2%	8.5%	6.1%	6.8%	9.3%	8.7%	9.8%	9.9%	9.2%	9.7%	7.9%	9.1%	9.5%	9.5%	10.0%
PNM Resources, Inc.	6.3%	6.7%	7.9%	8.6%	8.4%	3.4%	0.5%	3.1%	4.8%	5.8%	6.6%	6.9%	6.7%	7.6%	6.0%	5.9%	7.5%	8.0%	9.5%
Portland General Electric Co.					5.9%	11.5%	6.5%	6.2%	8.0%	9.0%	8.3%	7.7%	9.1%	8.2%		8.1%	8.0%	9.0%	9.0%
Westar Energy, Inc.	5.0%	10.6%	7.7%	9.6%	11.1%	10.0%	6.7%	6.3%	8.6%	8.2%	9.5%	9.8%	9.7%	8.2%	8.7%	8.6%	9.0%	10.0%	10.5%
Average	9.4%	8.7%	8.3%	9.3%	9.0%	9.0%	7.2%	6.9%	7.3%	8.1%	8.1%	8.6%	8.7%	8.5%	8.8%	8.0%	8.5%	8.8%	9.3%
Median	8.6%	8.5%	8.2%	9.5%	9.3%	9.3%	6.8%	6.8%	8.0%	8.5%	8.1%	8.5%	8.9%	8.4%	8.6%	8.2%	8.8%	9.0%	9.3%

Source: Calculations made from data contained in Value Line Investment Survey.

PROXY COMPANIES
MARKET TO BOOK RATIOS

COMPANY	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2002-2008 Average	2009-2015 Average
Parcell Proxy Group																
ALLETE				212%	219%	195%	156%	113%	127%	138%	136%	152%	151%	146%		138%
Avista Corp	85%	94%	111%	115%	135%	127%	110%	94%	106%	119%	123%	125%	143%	141%	111%	122%
El Paso Electric	140%	120%	148%	176%	179%	179%	134%	102%	134%	164%	163%	161%	158%	152%	154%	148%
Great Plains Energy	163%	198%	218%	189%	181%	173%	113%	73%	87%	89%	97%	102%	116%	116%	176%	97%
IDACORP	134%	112%	125%	122%	139%	132%	104%	94%	113%	119%	123%	136%	159%	158%	124%	129%
NorthWestern Corp					160%	147%	109%	105%	122%	138%	146%	159%	174%	167%		144%
Otter Tail Corp	245%	209%	185%	183%	178%	200%	167%	108%	120%	123%	152%	196%	196%	186%	195%	154%
Portland General Corp					153%	140%	101%	83%	97%	10%	117%	131%	145%	148%		104%
PNM Resources	95%	93%	124%	147%	134%	125%	72%	50%	68%	86%	100%	109%	127%	129%	113%	96%
Westar Energy	67%	109%	132%	142%	139%	140%	107%	91%	111%	119%	133%	138%	155%	153%	119%	129%
Average	133%	134%	149%	161%	162%	156%	117%	91%	109%	111%	129%	141%	152%	150%	142%	126%
Median	134%	112%	132%	162%	157%	144%	110%	94%	112%	119%	128%	137%	153%	150%	136%	128%
Buckley Proxy Group																
ALLETE				212%	219%	195%	156%	113%	127%	138%	136%	152%	151%	146%		138%
American Electric Power	138%	124%	155%	165%	161%	190%	145%	112%	118%	128%	134%	145%	162%	166%	154%	138%
Duke Energy Corp	171%	108%	139%	157%	153%	102%	102%	90%	101%	115%	120%	120%	133%	135%	133%	116%
Empire District Electric	132%	133%	144%	148%	149%	150%	122%	100%	127%	128%	124%	131%	150%	144%	140%	129%
Eversource Energy	99%	95%	106%	108%	131%	163%	128%	114%	136%	150%	143%	141%	158%	158%	119%	143%
Great Plains Energy Inc.	163%	198%	218%	189%	181%	173%	113%	73%	87%	89%	97%	102%	116%	116%	176%	97%
IDACORP, Inc.	134%	112%	125%	122%	139%	132%	104%	94%	113%	119%	123%	136%	159%	158%	124%	129%
Otter Tail Corporation	245%	209%	185%	183%	178%	200%	167%	108%	120%	123%	152%	196%	196%	186%	195%	154%
Pinnacle West Capital Corp.	116%	114%	130%	130%	129%	127%	100%	90%	113%	125%	141%	153%	158%	160%	121%	134%
PNM Resources, Inc.	95%	93%	124%	147%	134%	125%	72%	50%	68%	86%	100%	109%	127%	129%	113%	96%
Portland General Electric Co.					153%	140%	101%	83%	97%	10%	117%	131%	145%	148%		104%
Westar Energy, Inc.	67%	109%	132%	142%	139%	140%	107%	91%	111%	119%	133%	138%	155%	153%	119%	129%
Average	136%	129%	146%	155%	156%	153%	118%	93%	110%	111%	127%	138%	151%	150%	139%	126%
Median	133%	113%	136%	148%	151%	145%	110%	93%	113%	121%	129%	137%	153%	151%	134%	128%

Source: Calculations made from data contained in Value Line Investment Survey.

Exhibit DCP-1
Schedule 11

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 2002 - 2014

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
2002	8.4%	295%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
2006	17.0%	277%
2007	12.8%	284%
2008	3.0%	224%
2009	10.6%	187%
2010	14.2%	208%
2011	14.6%	207%
2012	13.5%	214%
2013	14.5%	237%
2014	14.2%	268%
Averages:		
2002-2008	12.4%	275%
2009-2014	13.6%	220%

Source: Standard & Poor's Analyst's Handbook, 2015 edition.

RISK INDICATORS

COMPANY	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FINANCIAL STRENGTH		S& P STOCK RANKING	
Parcell Proxy Group						
ALLETE	2	0.80	A	4.00	A-	3.67
Avista Corp	2	0.75	A	4.00	A-	3.67
El Paso Electric	2	0.75	B++	3.67	B	3.00
Great Plains Energy	3	0.80	B+	3.33	B	3.00
IDACORP	2	0.80	A	4.00	A	4.00
NorthWestern Corp	3	0.70	B+	3.33	A+	4.33
Otter Tail Corp	3	0.85	B+	3.33	B	3.00
Portland General Corp	2	0.80	B++	3.67	NR	
PNM Resources	3	0.80	B	3.00	B	3.00
Westar Energy	2	0.75	B++	3.67	A-	3.67
	2.4	0.78	B+/B++	3.60	B+/A-	3.48
Buckley Proxy Group						
ALLETE	2	0.80	A	4.00	A-	3.67
American Electric Power	2	0.70	A	4.00	A-	3.67
Duke Energy Corp	2	0.50	A	4.00	B	3.00
Empire District Electric	2	0.70	B++	3.67	B+	3.33
Eversource Energy	1	0.75	A	4.00	A-	3.67
Great Plains Energy Inc.	3	0.80	B+	3.33	B	3.00
IDACORP, Inc.	2	0.80	A	4.00	A	4.00
Otter Tail Corporation	3	0.85	B+	3.33	B	3.00
Pinnacle West Capital Corp.	1	0.75	A+	4.33	B+	3.33
PNM Resources, Inc.	3	0.80	B	3.00	B	3.00
Portland General Electric Co.	2	0.80	B++	3.67	NR	
Westar Energy, Inc.	2	0.75	B++	3.67	A-	3.67
Average	2.1	0.75	B++	3.75	B+	3.39

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B
Parcell Proxy Group	2.4	0.78	B+/B++	B+/A-
Buckley Proxy Group	2.1	0.75	B++	B+

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the later representing the highest level.

LONG-TERM PROJECTIONS OF GROSS DOMESTIC PRODUCT GROWTH

Social Security Administration

Year	Real GDP	GDP Index	Nominal GDP
2020	2.70%	2.30%	5.00%
2021	2.60%	2.30%	4.90%
2022	2.40%	2.30%	4.70%
2023	2.20%	2.30%	4.50%
2024	2.20%	2.30%	4.50%
2025	2.20%	2.30%	4.50%
2026	2.20%	2.30%	4.50%
2027	2.20%	2.30%	4.50%
2028	2.20%	2.30%	4.50%
2029	2.20%	2.30%	4.50%
2030	2.10%	2.30%	4.40%
2031	2.10%	2.30%	4.40%
2032	2.10%	2.30%	4.40%
2033	2.10%	2.30%	4.40%
2034	2.10%	2.30%	4.40%
2035	2.10%	2.30%	4.40%
2036	2.10%	2.30%	4.40%
2037	2.10%	2.30%	4.40%
2038	2.10%	2.30%	4.40%
2039	2.10%	2.30%	4.40%
2040	2.20%	2.30%	4.50%
2041	2.20%	2.30%	4.50%
2042	2.20%	2.30%	4.50%
2043	2.20%	2.30%	4.50%
2044	2.20%	2.30%	4.50%
2045	2.10%	2.30%	4.40%
2046	2.10%	2.30%	4.40%
2047	2.10%	2.30%	4.40%
2048	2.10%	2.30%	4.40%
2049	2.10%	2.30%	4.40%
2050	2.10%	2.30%	4.40%
2051	2.10%	2.30%	4.40%
2052	2.10%	2.30%	4.40%
2053	2.10%	2.30%	4.40%
2054	2.10%	2.30%	4.40%
2055	2.10%	2.30%	4.40%
2056	2.10%	2.30%	4.40%
2057	2.10%	2.30%	4.40%
2058	2.10%	2.30%	4.40%
2059	2.10%	2.30%	4.40%
2060	2.00%	2.30%	4.30%
2061	2.00%	2.30%	4.30%
2062	2.00%	2.30%	4.30%
2063	2.00%	2.30%	4.30%
2064	2.00%	2.30%	4.30%
2065	2.00%	2.10%	4.10%
2066	2.00%	2.10%	4.10%
2067	2.00%	2.10%	4.10%
2068	2.00%	2.10%	4.10%
2069	2.00%	2.10%	4.10%
2070	2.00%	2.10%	4.10%
2071	2.00%	2.10%	4.10%
2072	2.00%	2.10%	4.10%
2073	2.00%	2.10%	4.10%
2074	2.00%	2.10%	4.10%
2075	2.00%	2.10%	4.10%
2076	2.00%	2.10%	4.10%
2077	2.00%	2.10%	4.10%
2078	2.00%	2.10%	4.10%
2079	2.00%	2.10%	4.10%
2080	2.00%	2.10%	4.10%
2081	2.00%	2.10%	4.10%
2082	2.00%	2.10%	4.10%
2083	2.00%	2.10%	4.10%
2084	2.00%	2.10%	4.10%
2085	2.00%	2.10%	4.10%
2086	2.00%	2.00%	4.00%
2087	2.00%	2.00%	4.00%
2088	2.00%	2.00%	4.00%
Average			**4.32%**

Source: 2015 OASDI Trustees Report.

LONG-TERM PROJECTIONS OF GROSS DOMESTIC PRODUCT GROWTH

Energy Information Administration

Annual Growth (2012-2040):

Real GDP	2.4%
GDP Chain-type Price Index	1.8%
Nominal GDP Growth	**4.2%**

Source: Energy Information Administration, Annual Energy Outlook 2015 with Projections to 2040.

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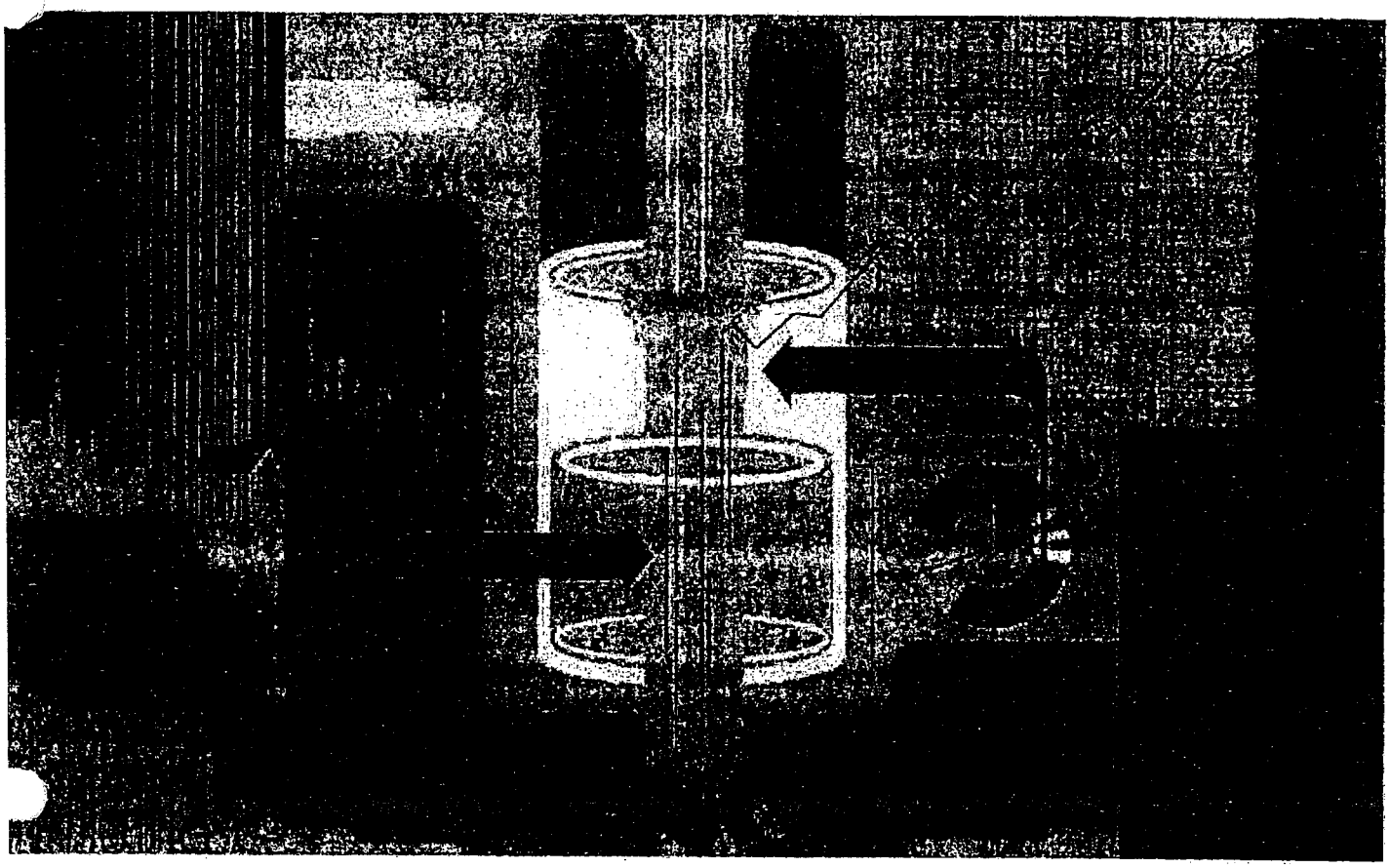
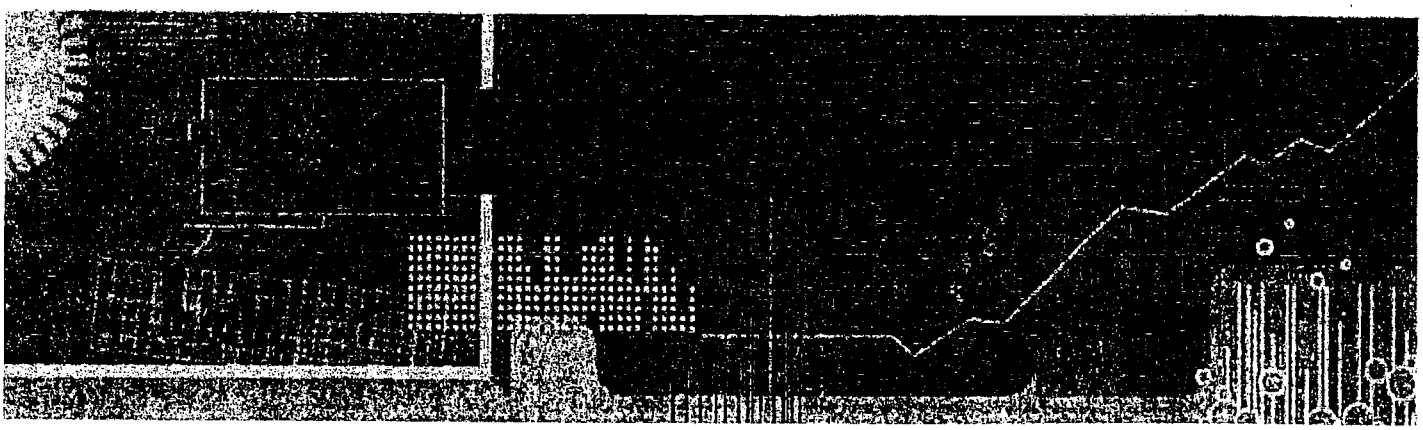




Equity analysts: Still too bullish

After almost a decade of stricter regulation, analysts' earnings forecasts continue to be excessively optimistic.

Marc H. Goedhart, Rishi Raj, and Abhishek Saxena

No executive would dispute that analysts' forecasts serve as an important benchmark of the current and future health of companies. To better understand their accuracy, we undertook research nearly a decade ago that produced sobering results. Analysts, we found, were typically overoptimistic, slow to revise their forecasts to reflect new economic conditions, and prone to making increasingly inaccurate forecasts when economic growth declined.[1]

Alas, a recently completed update of our work only reinforces this view—despite a series of rules and regulations, dating to the last decade, that were intended to improve the quality of the analysts' long-term earnings forecasts, restore investor confidence in them, and prevent conflicts of interest.[2] For executives, many of whom go to great lengths to satisfy Wall Street's expectations in their financial reporting and long-term strategic moves, this is a cautionary tale worth remembering.

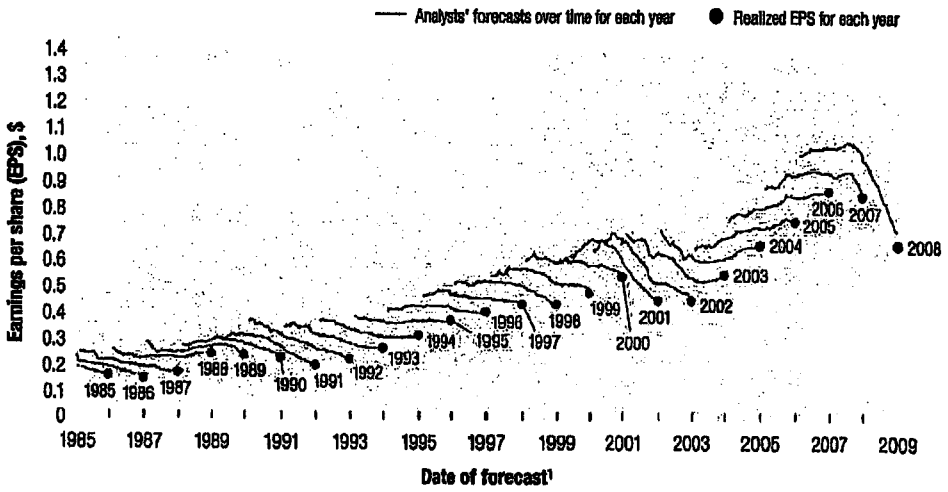
Exceptions to the long pattern of excessively optimistic forecasts are rare, as a progression of consensus earnings estimates for the S&P 500 shows (Exhibit 1). Only in years such as 2003 to 2006, when strong economic growth generated actual earnings that caught up with earlier predictions, do forecasts actually hit the mark.

Exhibit 1

Off the mark

With few exceptions, aggregate earnings forecasts exceed realized earnings per share.

S&P 500 companies



[1]Monthly forecasts.

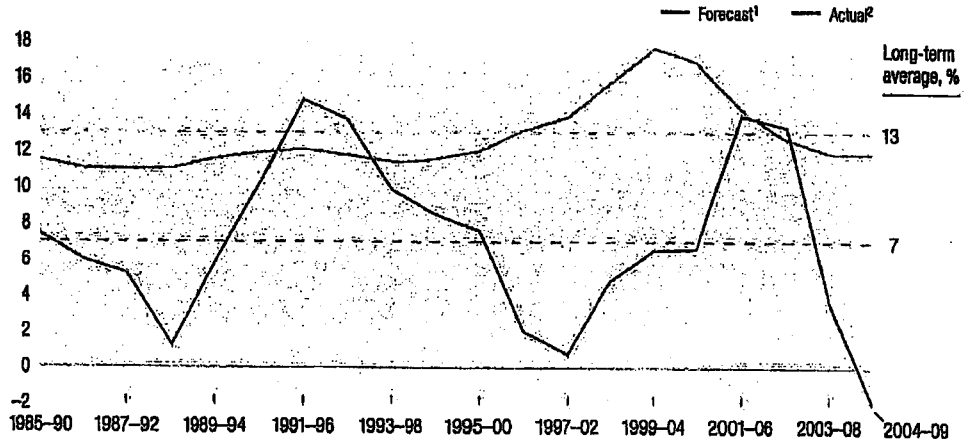
Source: Thomson Reuters I/B/E/S Global Aggregates; McKinsey analysis

Exhibit 2

Overoptimistic

Actual growth surpassed forecasts only twice in 25 years—both times during the recovery following a recession.

Earnings growth for S&P 500 companies, 5-year rolling average, %



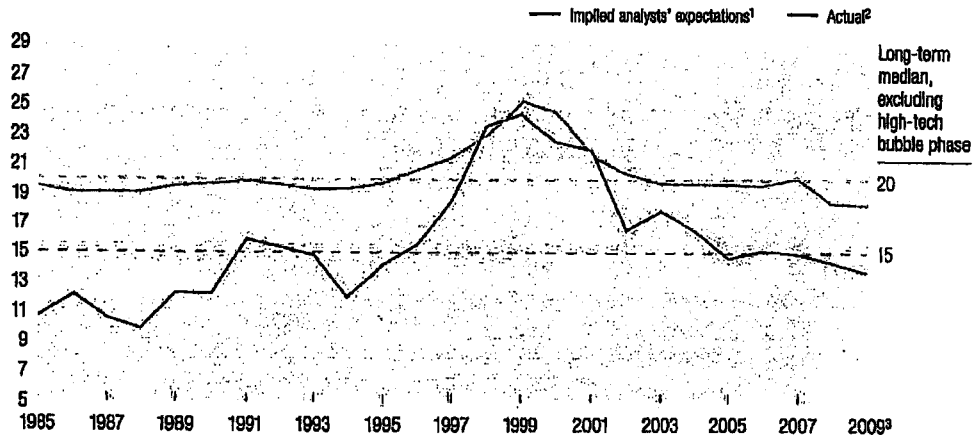
[1]Analysts' 5-year forecasts for long-term consensus earnings-per-share (EPS) growth rate. Our conclusions are same for growth based on year-over-year earnings estimates for 3 years.
[2]Actual compound annual growth rate (CAGR) of EPS; 2009 data are not yet available, figures represent consensus estimate as of Nov 2009.

Source: Thomson Reuters I/B/E/S Global Aggregates; McKinsey analysis

Exhibit 3
Less giddy

Capital market expectations are more reasonable.

Actual P/E ratio vs P/E ratio implied by analysts' forecasts, S&P 500 composite index



[1]P/E ratio based on 1-year-forward earnings-per-share (EPS) estimate and estimated value of S&P 500. Estimated value assumes: for first 5 years, EPS growth rate matches analysts' estimates then drops smoothly over next 10 years to long-term continuing-value growth rate; continuing value based on growth rate of 6%; return on equity is 13.5% (long-term historical median for S&P 500), and cost of equity is 9.5% in all periods.
[2]Observed P/E ratio based on S&P 500 value and 1-year-forward EPS estimate.
[3]Based on data as of Nov 2009.

Source: Thomson Reuters I/B/E/S Global Aggregates; McKinsey analysis

This pattern confirms our earlier findings that analysts typically lag behind events in revising their forecasts to reflect new economic conditions. When economic growth accelerates, the size of the forecast error declines; when economic growth slows, it increases.[3] So as economic growth cycles up and down, the actual earnings S&P 500 companies report occasionally coincide with the analysts' forecasts, as they did, for example, in 1988, from 1994 to 1997, and from 2003 to 2006.

Moreover, analysts have been persistently overoptimistic for the past 25 years, with estimates ranging from 10 to 12 percent a year,[4] compared with actual earnings growth of 6 percent.[5]

Over this time frame, actual earnings growth surpassed forecasts in only two instances, both during the earnings recovery following a recession (Exhibit 2). On average, analysts' forecasts have been almost 100 percent too high.[6]

Capital markets, on the other hand, are notably less giddy in their predictions. Except during the market bubble of 1999–2001, actual price-to-earnings ratios have been 25 percent lower than implied P/E ratios based on analyst forecasts (Exhibit 3). What's more, an actual forward P/E ratio[7] of the S&P 500 as of November 11, 2009—14—is consistent with long-term earnings growth of 5 percent.[8] This assessment is more

reasonable, considering that long-term earnings growth for the market as a whole is unlikely to differ significantly from growth in GDP,[9] as prior McKinsey research has shown.[10] Executives, as the evidence indicates, ought to base their strategic decisions on what they see happening in their industries rather than respond to the pressures of forecasts, since even the market doesn't expect them to do so.

[1] Marc H. Goedhart, Brendan Russell, and Zane D. Williams, "Prophets and profits," mckinseyquarterly.com, October 2001.

[2] US Securities and Exchange Commission (SEC) Regulation Fair Disclosure (FD), passed in 2000, prohibits the selective disclosure of material information to some people but not others. The Sarbanes–Oxley Act of 2002 includes provisions specifically intended to help restore investor confidence in the reporting of securities' analysts, including a code of conduct for them and a requirement to disclose knowable conflicts of interest. The Global Settlement of 2003 between regulators and ten of the largest US investment firms aimed to prevent conflicts of interest between their analyst and investment businesses.

[3] The correlation between the absolute size of the error in forecast earnings growth (S&P 500) and GDP growth is –0.55.

[4] Our analysis of the distribution of five-year earnings growth (as of March 2005) suggests that analysts forecast growth of more than 10 percent for 70 percent of S&P 500 companies.

[5] Except 1998–2001, when the growth outlook became excessively optimistic.

[6] We also analyzed trends for three-year earnings-growth estimates based on year-on-year earnings estimates provided by the analysts, where the sample size of analysts' coverage is bigger. Our conclusions on the trend and the gap vis-à-vis actual earnings growth does not change.

[7] Market-weighted and forward-looking earnings-per-share (EPS) estimate for 2010.

[8] Assuming a return on equity (ROE) of 13.5 percent (the long-term historical average) and a cost of equity of 9.5 percent—the long-term real cost of equity (7 percent) and inflation (2.5 percent).

[9] Real GDP has averaged 3 to 4 percent over past seven or eight decades, which would indeed be consistent with nominal growth of 5 to 7 percent given current inflation of 2 to 3 percent.

[10] Timothy Koller and Zane D. Williams, "What happened to the bull market?" mckinseyquarterly.com, November 2001.

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Analyzing Analyst Recommendations

Research analysts study publicly traded companies and make recommendations on the securities of those companies. Most specialize in a particular industry or sector of the economy. They exert considerable influence in today's marketplace. Analysts' recommendations or reports can influence the price of a company's stock—especially when the recommendations are widely disseminated through television appearances or through other electronic and print media. The mere mention of a company by a popular analyst can temporarily cause its stock to rise or fall—even when nothing about the company's prospects or fundamentals has recently changed.

Analysts often use a variety of terms—buy, strong buy, near-term or long-term accumulate, near-term or long-term over-perform or under-perform, neutral, hold—to describe their recommendations. But the meanings of these terms can differ from firm to firm. Rather than make assumptions, investors should carefully read the definitions of all ratings used in each research report. They should also consider the firm's disclosures regarding what percentage of all ratings fall into either "buy," "hold/neutral," and "sell" categories.

While analysts provide an important source of information in today's markets, investors should understand the potential conflicts of interest analysts might face. For example, some analysts work for firms that underwrite or own the securities of the companies the analysts cover. Analysts themselves sometimes own stocks in the companies they cover—either directly or indirectly, such as through employee stock-purchase pools in which they and their colleagues participate.

As a general matter, investors should not rely solely on an analyst's recommendation when deciding whether to buy, hold, or sell a stock. Instead, they should also do their own research—such as reading the prospectus for new companies or for public companies, the quarterly and annual reports filed with the SEC—to confirm whether a particular investment is appropriate for them in light of their individual financial circumstances. This alert discusses the potential conflicts of interest analysts face, describes the New York Stock Exchange (NYSE) and FINRA rules concerning analyst recommendations, and provides tips for researching investments.

Who Analysts Are and Who They Work for

Analysts historically have served an important role, promoting the efficiency of our markets by ferreting out facts and offering valuable insights on companies and industry trends. Analysts generally fall into one of three categories:

Sell-side analysts typically work for full-service broker-dealers and make recommendations on the securities they cover. Many of the more popular sell-side analysts work for prominent brokerage firms that also provide investment banking services for corporate clients—including companies whose securities the analysts cover.

Buy-side analysts typically work for institutional money managers—such as mutual funds, hedge funds, or investment advisers—that purchase securities for their own accounts. They counsel their employers on which securities to buy, hold, or sell and stand to make money when they make good calls.

Independent analysts typically aren't associated with firms that underwrite the securities they cover. They often sell their research reports on a subscription or other basis. Some firms that have discontinued their investment banking operations now market themselves as more independent than multi-service firms, emphasizing their lack of conflicts of interest.

Potential Conflicts of Interest

Many analysts work in a world with built-in conflicts of interest and competing pressures. On the one hand, sell-side firms want their individual investor clients to be successful over time because satisfied long-term investors are a key to a firm's long-term reputation and success. A well-respected investment research team is an important service to customers.

At the same time, however, several factors can create pressure on an analyst's independence and objectivity. The existence of these factors does not necessarily mean that the research analyst is biased. But investors should take them into account before making an investment decision. Some of these factors include:

- **Investment Banking Relationships**—When companies issue new securities, they hire investment bankers for advice on structuring the deal and for help with the actual offering. Underwriting a company's securities offerings and providing other investment banking services can bring in more money for firms than revenues from brokerage operations or research reports. Here's what an investment banking relationship may mean:

    1. **The analyst's firm may be underwriting the offering**—If so, the firm has a substantial interest—both financial and with respect to its reputation—in assuring that the offering is successful. Analysts are often an integral part of the investment banking team for initial public offerings—assisting with "due diligence" research into the company, participating in investor road shows, and helping to shape the deal. Upbeat research reports and positive recommendations published after the offering is completed may "support" new stock issued by a firm's investment banking clients.

    2. **Client companies prefer favorable research reports**—Unfavorable analyst reports may hurt the firm's efforts to

nurture a lucrative, long-term investment banking relationship. An unfavorable report might alienate the firm's client or a potential client and could cause a company to look elsewhere for future investment banking services.

3. **Positive reports attract new clients**—Firms must compete with one another for investment banking business. Favorable analyst coverage of a company may induce that company to hire the firm to underwrite a securities offering. A company might be unlikely to hire an underwriter to sell its stock if the firm's analyst has a negative view of the stock.

- **Brokerage Commissions**—Brokerage firms usually don't charge for their research reports. But a positive-sounding analyst report can help firms make money indirectly by generating more purchases and sales of covered securities—which, in turn, result in additional brokerage commissions.

- **Analyst Compensation**—Brokerage firms' compensation arrangements can put pressure on analysts to issue positive research reports and recommendations. For example, some firms link compensation and bonuses—directly or indirectly—to the number of investment banking deals the analyst lands or to the profitability of the firm's investment banking division.

- **Ownership Interests in the Company**—An analyst, other employees, and the firm itself may own significant positions in the companies an analyst covers. Analysts may also participate in employee stock-purchase pools that invest in companies they cover. And in a growing trend called "venture investing," an analyst's firm or colleagues may acquire a stake in a start-up by obtaining discounted, pre-IPO shares. These practices allow an analyst, the firm he or she works for, or both to profit, directly or indirectly, from owning securities in companies the analyst covers.

Disclosure and Recent Rule Changes

The rules of the NYSE and FINRA require analysts in some circumstances to disclose certain conflicts of interest when recommending the purchase or sale of a specific security. On May 10, 2002, the SEC approved proposed changes to these rules, strengthening the disclosures that analysts and firms must make. The NYSE and FINRA decided upon an implementation schedule of between 60 and 180 calendar days for the new rules in order to provide reasonable time periods for firms to develop and implement policies, procedures and systems to comply with the new requirements. These rules implement key structural reforms aimed at increasing analysts' independence and further managing conflicts of interest. They also require increased disclosure of conflicts in research reports and public appearances. Key provisions of the rules include the following:

- **No Promises of Favorable Research** — NYSE and FINRA rules now prohibit analysts from offering a favorable research rating or specific price target to induce investment banking business from companies. The rule changes also impose "quiet periods" that bar a firm that is acting as manager or co-manager of a

securities offering from issuing a report on a company within 40 days after an initial public offering or within 10 days after a secondary offering for an inactively traded company.

Significance of the Change: Promising research coverage to a company will not be as attractive if the research may not be issued within the initial days following the offering.

- **Limitations on Relationships and Communications** — The rule changes prohibit research analysts from being supervised by the investment banking department. In addition, investment banking personnel are prohibited from discussing research reports with analysts prior to distribution, unless staff from the firm's legal/compliance department monitor those communications. Analysts are also prohibited from sharing draft research reports with the target companies, other than to check facts after approval from the firm's legal/compliance department.

  Significance of the Change: These provisions help protect research analysts from influences that could impair their objectivity and independence.

- **Analyst Compensation** — The rule changes bar securities firms from tying an analyst's compensation to specific investment banking transactions. Furthermore, if an analyst's compensation is based on the firm's general investment banking revenues, that fact must be disclosed in the firm's research reports.

  Significance of the Change: Prohibiting compensation from specific investment banking transactions significantly curtails a potentially major influence on research analysts' objectivity.

- **Firm Compensation** — The rule changes require a securities firm to disclose in a research report if it managed or co-managed a public offering of equity securities for the company or if it received any compensation for investment banking services from the company in the past 12 months. A firm also must disclose if it expects to receive or intends to seek compensation for investment banking services from the company during the next 3 months.

  Significance of the Change: Requiring securities firms to disclose compensation from investment banking clients can alert investors to potential biases in their recommendations.

- **Restrictions on Personal Trading by Analysts** — The rule changes bar analysts and members of their households from investing in a company's securities

prior to its initial public offering if the company is in the business sector that the analyst covers. In addition, the rule changes require "blackout periods" that prohibit analysts from trading securities of the companies they follow for 30 days before and 5 days after they issue a research report about the company, and also prohibits analysts from trading against their most recent recommendations—subject to exceptions for unanticipated significant changes in the personal financial circumstances of the beneficial owner of a research analyst account.

Significance of the Change: Prohibiting analysts from trading around the time they issue research reports should reduce conflicts arising from personal financial interests.

- **Disclosures of Financial Interests in Covered Companies** — The rule changes require analysts to disclose if they own shares of recommended companies. Firms are also required to disclose if they own 1% or more of a company's equity securities as of the previous month end.

  Significance of the Change: Requiring analysts and securities firms to disclose financial interests can alert investors to potential biases in their recommendations.

- **Disclosures in Research Reports Regarding the Firm's Ratings** — The rule changes require firms to clearly explain in research reports the meaning of all ratings terms they use, and this terminology must be consistent with its plain meaning. Additionally, firms must provide the percentage of all the ratings that they have assigned to buy / hold / sell categories and the percentage of investment banking clients in each category. Firms are also required to provide a graph or chart that plots the historical price movements of the security and indicates those points at which the firm initiated and changed ratings and price targets for the company.

  Significance of the Change: These disclosures will assist investors in deciding what value to place on a securities firm's ratings and provide them with better information to assess its research.

- **Disclosures During Public Appearances by Analysts** — The rule changes require disclosures from analysts during public appearances, such as television or radio interviews. Guest analysts will have disclose if they or their firm have a position in the stock; if the company is an investment banking client of the firm; if the analyst or a member of the analyst's household is an officer, director or advisory board member of the

recommended issuer; and other material conflicts.

> **Significance of the Change:** This disclosure will inform investors who learn of analyst opinions and ratings through the media — rather than in written research reports — of analyst and firm conflicts.

What Conflicts May Mean to You

The fact that an analyst—or the analyst's firm—may have a conflict of interest does not mean that his or her recommendation is flawed or unwise. But it's a fact you should know and consider in assessing whether the recommendation is wise *for you*.

It's up to you to educate yourself to make sure that any investments you choose match your goals and tolerance for risk. Remember that analysts generally do not function as your financial adviser when they make recommendations—they're not providing individually tailored investment advice, and they're not taking your personal circumstances into consideration.

Uncovering Conflicts

In addition to paying close attention to the disclosures that firms and analysts make, here are some steps you can take to assess whether and to what extent analyst conflicts may exist:

Identify the Underwriter

Before you buy, confirm whether the analyst's firm underwrote a recommended company's stock by looking at the prospectus, which is part of the registration statement for the offering. Note that firms are required to disclose in research reports whether they managed or co-managed a public offering. You'll find a list of the lead or managing underwriters on the front cover of both the preliminary and final copies of the prospectus. By convention, the name of the lead underwriter—the firm that stands to make the most money on the deal—will appear first, and any co-managers will generally be listed second in alphabetical order. Other firms participating in the deal will be listed only in the "Underwriting" or "Plan of Distribution" sections of the final supplement to the prospectus. You can search for registration statements using the SEC's EDGAR database at www.sec.gov/edgar.shtml. The final supplement to the prospectus will appear in EDGAR as a "424" filing.

Research Ownership Interests

A company's registration statement and its annual report on Form 10-K will tell you who the beneficial owners of more than five percent of a class of equity securities are. Research reports on a company must disclose whether the securities firm issuing the report (or any of its affiliates) beneficially owns one percent or more of any class of common equity securities of the subject company. The issuer's registration statement will also tell you

about private sales of the company's securities during the past three years. In addition to the disclosure requirements in the new rules, you may be able to ascertain ownership by checking the following SEC forms:

- **Schedules 13D and 13G**—Any person who acquires a beneficial ownership of more than five percent must file a Schedule 13D. Schedule 13G is a much abbreviated version of Schedule 13D that is only available for use by a limited category of "persons," such as banks, broker-dealers, or insurance companies.

- **Forms 3, 4, and 5**—Officers, directors, and beneficial owners of more than 10 percent must report their holdings—and any changes in their holdings—to the SEC on Forms 3, 4, and 5.

- **Form 144**—If an analyst or a firm holds "restricted" securities from the company—meaning those acquired in an unregistered, private sale from the issuer or its affiliates—then investors can find out whether the analyst or the firm recently sold the stock by researching their Form 144 filings.

As of November 4, 2002, all statements of beneficial ownership on Schedules 13D and 13G (including those relating to the securities of foreign private issuers) must be submitted electronically using the SEC's EDGAR system. If you can't find a form on EDGAR, please refer to information on "How to Request Public Documents" at http://www.sec.gov/answers/publicdocs.htm. Or check the "Quotes" section of the Nasdaq Stock Market's website at http://quotes.nasdaq.com/

Unlock the Mystery of "Lock-ups"

If the analyst's firm acquired ownership interests through venture investing, the shares generally will be subject to a "lock-up" agreement during and after the issuer's initial public offering. Lock-up agreements prohibit company insiders—including employees, their friends and family, and venture capitalists—from selling their shares for a set period of time without the underwriter's permission. While the underwriter can choose to end a lock-up period early—whether because of market conditions, the performance of the offering, or other factors—lock-ups generally last for 180 days after the offering's registration statement becomes effective.

After the lock-up period ends, the firm may be able to sell the stock. If you're considering investing in a company that has recently conducted an initial public offering, you'll want to check whether a lock-up agreement is in effect and when it expires or if the underwriter waived any lock-up restrictions. This is important information because a company's stock price may be affected by the prospect of lock-up shares being sold into the market when the lock-up ends. It is also a data point you can

consider when assessing research reports issued just before a lock-up period expires—which are sometimes known as "booster shot" reports.

To find out whether a company has a lock-up agreement, check the "Underwriting" or "Plan of Distribution" sections of the prospectus. That's where companies must disclose that information. You can contact the company's shareholder relations department to ask for its prospectus, or use the SEC's EDGAR database if the company has filed its prospectus electronically. If you can't find a form on EDGAR, please refer to information on "How to Request Public Documents" at http://www.sec.gov/answers/publicdocs.htm. There are also commercial websites you can use for free that track when companies' lock-up agreements expire. The SEC does not endorse these websites and makes no representation about any of the information or services contained on these websites.

How You Can Protect Yourself

We advise all investors to do their homework before investing. If you purchase a security solely because an analyst said the company was one of his or her "top picks," you may be doing yourself a disservice. Especially if the company is one you've never heard of, take time to investigate:

- When assessing a firm's research report of a company, be sure to read all of the disclosures about the firm and analysts' conflicts of interest and the types of research recommendations that the firm has made.
- Research the company's financial reports using the SEC's EDGAR database at http://www.sec.gov/edgar.shtml, or call the company for copies. If you can't analyze them on your own, ask a trusted professional for help.
- Find out if a lock-up period is about to expire or whether the underwriter waived it. While that may not necessarily affect your decision to buy, it may put an analyst recommendation in perspective.
- Confirm whether the analyst's firm underwrote one of the company's recent stock offerings—especially its IPO.
- Learn as much as you can about the company by reading independent news reports, commercial databases, and reference books. Your local library may have these and other resources.
- Talk to your broker or financial adviser and ask questions about the company and its prospects. But bear in mind that if your broker's firm issued a positive report on a company, your broker will be hard-pressed to contradict it. Be sure to ask your broker whether a particular investment is suitable for you in light of your

financial circumstances.

Above all, always remember that even the soundest recommendation from the most trust-worthy analyst may not be a good choice for you. That's one reason we caution investors never to rely solely on an analyst's recommendation when buying or selling a stock. Before you act, ask yourself whether the decision fits with your goals, your time horizon, and your tolerance for risk. Know what you're buying—or selling—and why.

http://www.sec.gov/investor/pubs/analysts.htm

We have provided this information as a service to investors. It is neither a legal interpretation nor a statement of SEC policy. If you have questions concerning the meaning or application of a particular law or rule, please consult with an attorney who specializes in securities law.

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

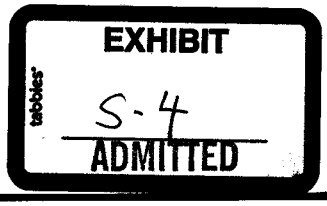
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-01933A-15-0322

REDACTED DIRECT TESTIMONY

OF

MICHAEL J. MCGARRY, SR.
ON BEHALF OF THE
UTILITIES DIVISION STAFF
ARIZONA CORPORATION COMMISSION

JUNE 3, 2016



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EXECUTIVE SUMMARY
TUSCON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-15-0322 ET. AL.

The Direct Testimony of Michael J. McGarry, Sr., of Blue Ridge Consulting Services, Inc. ("Blue Ridge") provides the results of the engineering assessment of Tucson Electric Power Company ("TEP" or "Company") as authorized by the Arizona Corporation Commission ("ACC" or "Commission") pursuant to requests and direction from the Commission's Utility Division Staff ("Staff" or "ACC Staff"). In addition, Mr. McGarry was particularly involved with several areas of Staff's review, including certain rate base and revenue requirement adjustments, the power supply section, and engineering evaluation.

Overall, Mr. McGarry found that the Company has overstated its request for a "normalized" outage expense of $5.176 million by including an adjustment based on the annual average expected outage/overhaul expenses from 2008 through 2024. Consistent with Staff's recommendation in Docket No. E-01933A-12-0291, Mr. McGarry recommends the Commission reject the Company's proposed adjustment and adopt an adjustment using a similar approach but using only historical costs back to 2012—to coincide with the Company's last rate case.

With respect to base cost of fuel, Mr. McGarry reviewed the back-up calculations and confirmed that the base cost of fuel adjustment is properly reflected in the Company's revenue requirement calculation. As such, he recommends acceptance of the Company's proposed rate of 3.3692¢ per kWh as the base rate cost of fuel in this case.

With respect to the impacts of recent legal developments related to the Obama Administration's Clean Power Plan ("CPP"), Mr. McGarry recommends that within six months of a decision on whether the CPP will be implemented, the Company review its then current Integrated Resource Plan ("IRP") and related plan retirements of its coal fleet and provide an assessment to the Staff in which the Company fully evaluates the long-term costs and benefits of delaying or otherwise modifying its retirement/compliance strategy should it be determined that these new rules be substantially delayed (or expedited).

Mr. McGarry also recommends rejecting the Company's proposal to include non-fuel O&M associated with the 50.5 percent co-owner share of the output from Springerville Unit No. 1 through the Purchased Power and Fuel Adjustment Clause ("PPFAC").

The major elements of the engineering analysis included evaluation of TEP's electric service quality, maintenance practices, and distribution system reliability indices; examination of TEP's assets to determine the used and useful nature of what was included in the proposed rate base; review of TEP's peak demand, system energy, and the number and types of customers; review of TEP's system losses; review of TEP's construction/capital expenditures since the last rate case; and evaluation of TEP's expenditures regarding such issues as growth and reliability improvement. The field inspections relating to examination of the assets were performed by Mr. McGarry and Mr. Freedman during the week of March 28 through April 1, 2016, and included discussions with TEP technical, management, and systems operations personnel.

Overall, the engineering analysis proved the Company's operations, maintenance and construction project management are reasonable. However, the cost rate that should be charged for the solar power should reflect the Company's fully allocated cost of the production from the solar project—not the station average. Mr. McGarry recommends that the Company modify its accounting to ensure that the fully allocated cost of production from the solar project at the station is credited or provide justification showing that the value of the solar project is properly reflected and customers are not subsidizing this portion of costs at the station.

Also, according to the requirements of the settlement in E-01933A-12-0291, TEP agreed to meet annually with Staff to review the Company's actual capital spending and future plans for the upcoming year. Mr. McGarry recommends that these meetings continue as Staff has conveyed that they were useful in gaining a clearer picture of what the Company was planning for the upcoming years.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Michael J. McGarry, Sr. I am a Senior Technical Consultant with Blue Ridge Consulting Services, Inc. My business address is 114 Knights Ridge Road Travelers Rest, SC 29690.

BACKGROUND AND QUALIFICATIONS

Q. Please state your experience and educational background.

A. From 2004 until May 2016, I was President of Blue Ridge Consulting Services, Inc. In my career, I have overseen or been part of numerous rate case audits, prudency reviews, and management and operational audits. I have worked with clients to manage various aspects of the regulatory and rate case process; prepared supporting analyses and testimony for submission to regulatory bodies and interveners; prepared revenue requirement and cost of service analyses; and developed complex revenue requirement models to present alternative positions to utilities' proposed rate requests. Prior to assuming my position with Blue Ridge Consulting Services, Inc., I was Vice President of East Coast Operations from July 2003 to June 2004 with Hawks, Giffels and Pullin (HGP), Inc. In that position, I was responsible for developing and overseeing client engagements in utility regulatory affairs, management audits, and rate case management. From August 2001 to July 2003, I was an independent consultant working on a number of different projects, including a renewal/update of delivery service tariffs for Illinois Power and several utility street lighting cost benefit assessment projects. From June 2000 until August 2001, I was a senior consultant with Denali Consulting, Inc., a utility supply chain and e-procurement strategy and implementation firm. From October 1997 through June 2000, I was employed by Navigant Consulting, Inc. and several of its predecessors or acquired firms, working on a number of different projects, including a management audit of Southern Connecticut Gas Company and the original delivery service

tariff filing for Illinois Power. From July 1985 through October 1997, I was employed by the New York State Department of Public Service ("NYSDPS") in its Utility Operational Audit Section in which the staff conducted focused operational audits in many facets of utility operations for all sectors of the utility industry, including gas, electric, telecommunications, and water. Prior to my employment with the NYSDPS, I was a rate analyst with Orange and Rockland Utilities (1981 to 1983) and then with Seminole Electric Cooperative (1983 to 1985). I received my Masters of Business Administration from the State University of New York at Buffalo in 1996 and a Bachelor of Arts in Economics from Potsdam College (SUNY) in 1981.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment MJM-1 provides details concerning my experience and qualifications.

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes. I have testified in Docket Nos. E-01345A-11-0224, E-04204A-12-0504, and E-01933A-12-0291.

Q. Have you testified before commissions in other jurisdictions?

A. Yes. I have testified in Delaware, Georgia, Illinois, Maine, Maryland, Michigan, Missouri, Nebraska, New York, North Dakota, Nova Scotia, Ohio, and Utah. These proceedings included testimony involving revenue requirements, power supply costs, management decisions and prudence impacts, operations and maintenance expenses, capital investments, and project management. A complete list is included in Attachment MJM-1.

I have also presented topics before staff groups from regulatory commissions, NARUC sub-committee groups, and as a program faculty member for the Institute of Public Utilities at Michigan State University. Topics presented include management auditing and prudence reviews, service company costs and allocations, forecasting methodology and modeling, revenue requirements, rate base, and price regulation theory.

PURPOSE OF TESTIMONY

Q. On whose behalf are you testifying?

A. I am appearing on behalf of the Arizona Corporation Commission ("Commission") Utilities Division Staff ("Staff").

Q. What is the purpose of the testimony you are presenting?

A. I am presenting the Staff's position with respect to Tucson Electric Power Company's ("TEP" or "Company") overhaul and outage expenses, power supply including the base cost of fuel and Purchased Power and Fuel Adjustment Clause ("PPFAC") and a proposal to include non-fuel O&M associated with TEP's use of the 50.5 percent portion of Springerville Unit 1 which TEP operates on behalf of two co-owners, and the engineering evaluation. In a subsequent filing, I will be presenting rate design testimony on the Company's proposed changes to the PPFAC. Finally, I present my findings related to the engineering assessment of the Company's operations.

Q. Was this testimony and the supporting analyses prepared by you or under your direct supervision?

A. Yes.

Q Please briefly describe the information you reviewed in preparation for your testimony.

A. I have reviewed the Company's testimony and exhibits and data request responses provided by the Company to the various parties to this proceeding.

CONTENT OF ATTACHMENTS TO TESTIMONY

Q. Have you attached any exhibits to your testimony?

A. Yes. The following Exhibits are included with my testimony.

MJM-1	Michael J. McGarry, Sr. Experience and Qualifications
MJM-2	Schedule 1 – Staff's Derivation of Overhaul and Outage Normalization
MJM-3	TEP's Income-Overhaul_Outage Normalization Adjustment Workpaper
MJM-4	TEP's Response to STF 17.07
MJM-5	TEP's Response to STF 5.04
MJM-6	TEP's Response to STF 5.05
[redacted]	
MJM-8	TEP's Response to STF 9.006 (voluminous)
MJM-9	TEP's Response to STF 9.006 - **CCP Patrol Criteria**
MJM-10	**TEP's Response to STF 9.006 – Transmission Inspection Patrol**
MJM-11	TEP's Response to STF 5.001
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MJM-18	TEP's Response to UDR 1.001 – Gray Workpapers C – TEP Capital Expenditures

OVERHAUL AND OUTAGE NORMALIZATION ADJUSTMENT

Q Staff Witness Mullinax indicated that you would address the derivation associated with the Company's proposed overhaul and outage expense. Is that correct?

A. Yes.

Q Please describe Staff's adjustment to the Company's proposed overhaul and outage normalization pro forma adjustment.

A. Staff has determined that the Company has overstated its request for a "normalized" outage expense of $5.176 million by including an adjustment based on the annual average expected outage/overhaul expenses from 2008 through 2024. Consistent with Staff's recommendation in Docket No. E-01933A-12-0291, I recommend the Commission reject the Company's proposed adjustment and adopt an adjustment using a similar approach but using only historical costs back to 2012—the time of the Company's last rate case.

Q What is the adjustment you propose?

A. I propose that the Commission reduce the amount of the Company's proposed adjustment by $4.131 million, resulting in a pro forma amount of $1.046 million. Exhibit MJM-2 Schedule 1 – Staff's Derivation of Overhaul and Outage Normalization summarizes Staff's adjustment.

Q Please continue.

A. The Company is proposing to increase O&M expense by $5.176 million on a jurisdictional basis.[1] The Company developed this amount by preparing a complicated assessment of past and future estimated overhaul and outage costs by generating unit and the frequency at which these outages occur. The goal of the analysis was to arrive at a levelized annual expense by unit to compare to the test year expenses for those units. This analysis included projected costs for outages, categorized as either "major" or "minor," through 2024. I have included the Company's workpaper for this calculation as Exhibit MJM-3 – Income-Overhaul_Outage Normalization.

[1] Schedule C-2 page 9 of 12, line 6, Column labeled "Overhaul and Outage Normalization".

Q Did TEP propose a similar methodology in Docket No. E-01933A-12-0291?

A. Yes. And the Company indicated that its proposed methodology in this case was consistent with that case.[2]

Q Do you agree with that characterization?

A. No, I do not. That case was settled and the specific issue is **not addressed** in the Commission's decision. However, the derivation of the revenue requirement resulting from the settlement shows that the parties agreed to a $1.322 million reduction to Overhaul and Outage Expense versus a $1.191 million increase that the Company was proposing.[3] This reduction ($2.514 million) matches Staff Witness Ralph Smith's proposed adjustment to the Company's level of expense as proffered in his testimony.[4] Therefore, the Company's claim that its proposed adjustment is consistent with the last case is incorrect.

Q How did Staff Witness Smith arrive at his adjustment?

A. He used the same complicated average cost and frequency methodology by unit that the Company developed but limited costs to only the actual/historical costs for the period 2004 to 2011.

Q Are you proposing anything different?

A. Yes. I am proposing a simplification. I calculated the adjustment using the average outage expense by unit for 2012 through 2015. I then compared that amount to the test year amount for the unit to determine whether an adjustment to test year level of expenses was necessary. I am including an exhibit (Exhibit MJM-2 – Derivation of Staff's adjustment to Overhaul and Outage expenses) that shows my calculations.

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[2] Direct testimony of Dallas Dukes, page 55, lines 10-12.
[3] Decision 73912 – Settlement Attachment A Page 3 of 4.
[4] Direct Testimony of Ralph Smith, page 31, Lines 11-16.

Q Why did you use only a four-year period rather than Staff's eight years as in Docket 12-0291?

A. I chose a four-year period to reflect the typical methodology to normalize expenses between base rate cases. The idea is that the levelized expense in the last case covered up to the test year in that case. My methodology simply picks up where that analysis left off and captures costs since the last test year.

Q Is this methodology consistent with other adjustments made by Staff in this case?

A. Yes. Rate case expense is a good example where expenses since the last case are compared to test year levels. My proposed methodology does just that—covers an average expense through 12/31/15. As shown in my exhibit, some adjustments are higher than the Company's, while others are lower. This effect is to be expected when a shorter timeframe is used. However, on average, the amount Staff is proposing is a fair and reasonable representation of the level of overhaul and outage expense the Company will likely experience. That is the goal of a normalization adjustment.

BASE COST OF FUEL AND PPFAC

Q What is TEP proposing for base cost of fuel and purchased power?

A. TEP calculated a base cost of fuel of $302,564,000 based on an average annual cost of $0.033692¢/kWh.[5] The current rate approved in the Commission Decision No. 73912, is $0.032335/kWh. TEP's calculated cost represents an increase of $0.001357/kWh or 4.2 percent. However, the Company is also proposing a modification to the PPFAC, which at the outset of the new rates would mean a $0.0 PPFAC charge to customers. Currently, the PPFAC rate is set at $0.001501.[6]

[5] Direct Testimony of Michael Sheehan at page 41 – Table 15 – 2017 Base Cost of Fuel and Purchased Power.
[6] See PPFAC filing dated February 1, 2016, Schedule 1.

Q Did TEP propose any adjustment to the base cost of fuel?

A. Yes. Witness Sheehan reduced the base cost of fuel and purchased power by approximately $2.7 million to reflect the loss of the margins associated with a wholesale contract with Shell Energy North that is set to expire at the end of 2017. The Company argues that this adjustment is necessary since there will be less than a year left in the contract with Shell after the rates in this docket are expected to be effective.[7]

Q Is the Company's position with respect to this adjustment reasonable?

A. Yes. Staff has reviewed the back-up calculations and confirmed that the base cost of fuel adjustment is properly reflected in the Company's revenue requirement calculation.

Q In the UNS Electric ("UNS") Case Docket No. E-04204A-15-0142, Staff Witness Keene recommended using actual costs to calculate the base cost of fuel. Why do you not propose using the same methodology here?

A. At the time that Witness Keene testified in E-04204A-15-0142 (November 2015), fuel costs, in particular, natural gas were at record lows. That fact, combined with the issue of the Gila River acquisition-related fuel costs, which were not reflected in UNS' filing, made it reasonable for Staff to take a balanced approach and include costs for Gila River and, at the same time, reflect low fuel costs.[8] In this case, the Company's proposed rate reflects the current market trends and includes the impact of Gila River in its derivation of the future net power costs.

[7] Direct testimony of Michael Sheehan at page 41, lines 15-22.
[8] It should be noted that Staff recommended an increase to UNS's base cost of fuel - $85,303,919 versus $77,522,386 – See Direct Testimony of Barbara Keene in Docket No 15-1042 at page 9, line 11 and page 10, line 16, respectively.

Q Were there any issues related to the amount of the base cost of fuel from the previous TEP case that should be addressed in this case?

A. Yes. The only issue was one related to the treatment of sulfur credits. Staff Witness Ralph Smith recommended in Docket No. E-01933A-12-0291 that sulfur credits (which are received for poorer quality coal) be recorded in FERC Account 501 when the coal is burned. The Company had proposed to include these credits in account 502 – Fuel Handling Expense. As part of the settlement stipulation, the parties agreed to include in the PPFAC a one-time credit of $3 million and a credit to the PPFAC of $9.7 million of deferred costs related to the San Juan Thermal event. Both of these items have been resolved.

Q Is the Company proposing any changes to costs that will be PPFAC eligible?

A. Yes. The Company is proposing to include in the PPFAC costs used to comply with federal Mercury and Air Toxic Standards ("MATS") to remove mercury and associated compounds from generation emissions.[9]

Q What does the Company estimate will be the annual amount to comply with these MATS rules?

A. The Company is estimating that it will cost $4.025 million in capital costs and $1.848 million in annual O&M costs to comply with MATS.[10]

Q Does Staff have an opinion on this issue?

A. Staff concurs with the Company's position on the inclusion of MATS compliance costs in the PPFAC so long as the additives are procured at reasonable and prudent costs and are directly attributable to amount/volume of coal burned in the Company's generating units.

[9] Direct Testimony of Sheehan at page 43, lines 8-9
[10] Direct Testimony of Sheehan at page 14, Table 7 – MATS Rule Compliance Summary lines 3-7

Q With respect to the Company's regional haze compliance strategy, what is Staff's position?

A. Company Witness Sheehan describes TEP's strategy for complying with regional haze regulations. These regulations will impact the Company in the coming years, but except to the extent that the Company is already complying with existing standards, costs for future implementation are not reflected in the Company's request for a base rate increase.

Q Is there any development that should be reported to the Commission concerning the EPA's Clean Power Plan?

A. Yes. As the Commission is aware, the Obama Administration's push for rules to clean up emissions from fossil fuel power plants (referred to as Clean Power Plan) is expected to have a major impact on coal burning power plants in the United States. The Environmental Protection Agency issued the new rules in August 2015.[11] These rules seek to make substantial reduction in CO2 emissions from all fossil fuel power plants in the United States to address the global warming issue. These rules were challenged in federal court, and on February 16, 2016, the U.S. Supreme Court issued a stay of a lower court's ruling thereby delaying the implementation of these rules until the legal issues are resolved by the lower courts. Staff asked the Company to describe the impact of the stay on the Company's plans to close power plant units and also coal handling facilities. We asked that they be specific regarding which plants and units and which rate base and operating income pro forma adjustments would be impacted by the stay and resulting delay in the compliance with the CCP. We also asked if the stay does not impact rate case adjustments that they explain in detail why not. The following is the Company's full response to STF 17.07 (Exhibit MJM-4).

[11] For a complete description of the rules, see https://www.epa.gov/cleanpowerplan/fact-sheet-overview-clean-power-plan.

RESPONSE:

At this point, the stay of the Clean Power Plan (CPP) and the likely delay in its implementation will have no immediate effect on near term plans to close Power Plant units or the related Coal Handling facilities. Per TEP's IRP, the Company continues to look for opportunities to reduce coal fired generation and replace it with a mix of natural gas fired generation and renewables. For example, in March 2016, TEP notified the EPA that as a result of Regional Haze Rule requirements it would stop burning coal at its Sundt Generating Station and switch permanently to natural and landfill gas. Additionally, at the San Juan Generating Station, TEP will along with the other San Juan Participants, shut Units 2 and 3 at the end of 2017 due to regional haze reduction requirements. TEP owns 50 percent of Unit 2. The early retirements of these facilities is addressed in the testimony of Mr. Marino and reflected in the depreciation study sponsored by Dr. White.

Longer term, depending on the ultimate CPP compliance timeframe and the requirements for carbon reduction in the final Court-approved rule, TEP will, as part of its resource diversification plan, determine what future closures may be appropriate. Accordingly, there are no pro-forma adjustments to rate base or operating income related to the CPP.[12]

To summarize, the Company is not changing its plans on which units will be retired and when.

Q Do you have an opinion concerning this?

A. Yes. I recommend that the Company review its IRP and related plan retirements of its coal fleet and provide an assessment to the Staff within six months after a decision is reached in the federal courts on implementation. I recommend that the Company fully evaluate the long-term costs and benefits of delaying or otherwise modifying its retirement/compliance strategy should it be determined that these new rules be substantially delayed (or expedited). Essentially, there are many factors at play here, but the Commission should have facts of what the alternatives are given that the mandates that would require generating units to be shut down are in flux.

[12] Exhibit MJM-4 – Company's response to STF 17.07

Q Staff Witness Mullinax indicated in her testimony that you would comment on the Company's request to allow recovery of the non-fuel O&M associated with the 50.5 percent of Springerville Unit No. 1 that the Company does not currently own, is that correct?

A. Yes.

Q Please explain what the Company is proposing.

A. As mentioned in Witness Mullinax's testimony, the Company is proposing, to the extent that the output of Springerville Unit 1 generating capacity that the Company does not currently own (i.e., the 50.5 percent) is available for dispatch to meet TEP's retail load, to recover the costs (both fuel and non-fuel) in the PPFAC. The non-fuel costs to be included are direct O&M, property taxes, insurance costs, and coal handling facility costs.

Q Does the Company have an estimate of the level of these costs and the impact on the base cost of fuel rate?

A. Yes. Company Witness Sheehan provided a table (No. 16),[13] which identified these costs. That table shows that the jurisdictional amount of non-fuel-related costs for the 50.5 percent of Unit 1 would be $16.291 million. Table 17 on page 47 of Company Witness Sheehan's testimony shows the Company's estimate of the net impact on the base cost of fuel, after considering the projected fuel and purchased power savings, to be a reduction of approximately $525,000, or a $0.000058 reduction to the Company's proposed base cost of fuel rate of $0.033692/kWh. The new rate would be $0.033634/kWh.

[13] Direct Testimony of Michael Sheehan at page 46 lines 17-21

Q Do you have an opinion on the Company's request?

A. While I am certainly for lower costs for the benefit of ratepayers, I am concerned that the policy set here could lead to other non-fuel costs to be included in the PPFAC. Also, the timing of it is problematic since the transaction to acquire the 50.5 percent co-owners' share has not yet happened. To include non-fuel O&M now is not consistent with the principles and as mentioned, I am concerned that it is inappropriate to allow non-fuel related costs in the PPFAC.

Q What do you recommend?

A. I recommend that the Commission reject the Company's request to include the non-fuel O&M in the PPFAC. It will be more appropriate to consider this issue in the Company's next rate filing. Also, in response to a data request and as Witness Mullinax pointed out, the Company is amenable to non-fuel O&M cost recovery, but this should be addressed in the next rate case.

Q Is the Company proposing any changes to the PPFAC?

A. Yes. TEP is requesting a major change to the PPFAC to implement a monthly rolling average percentage based adjustment.[14] I will address this issue in the rate design testimony.

ENGINEERING EVALUATION

Q What was the scope of the engineering evaluation?

A. As part of the engineering evaluation, Blue Ridge was requested to review the following:

- TEP's electric system quality, distribution system reliability indices, and maintenance practices

[14] Direct Testimony of Craig A. Jones at page 77, lines 3-8.

- The "used and usefulness" of assets included in the proposed rate base included post-test year additions (This included a number of projects which were subject to field inspections.)

- The Company's peak demand, system energy, and numbers and types of customers

- System losses

- TEP's construction/capital expenditures since the last rate case

- The purpose of TEP's expenditures for such issues as growth and reliability improvement

Q Overall, what did you find from your evaluation?

A. Based on my examinations in all areas of the engineering assessment, I believe the Company's efforts are not unreasonable. I believe the Company's level of service appears reasonable. Based upon the data trends, size of the Company, demographic and geographical conditions, and statistics examined, the service reliability of the Company is also considered reasonable. I am reasonably confident that the Company does conduct effective maintenance of the equipment used to serve customers. Further, based upon the processes described and the statistics presented, the safety program of the Company is considered reasonable. In conducting field observations and questioning of Company personnel familiar with projects, I found that the Company exercised adequate project management and controls on the construction activities.

However, I found that the cost rate that should be charged for the solar power should reflect the Company's fully allocated cost of the production from the solar project—not the station

average as I suspect is used. I would recommend that the Company modify its accounting to ensure that the fully allocated cost of production from the solar project at the station is credited such that customers are not subsidizing the costs at the station.

Finally, according to the requirements of the settlement in E-01933A-12-0291, TEP agreed to meet annually with Staff to review the Company's actual capital spending and future plans for the upcoming year. I would recommend that these meetings continue as Staff has conveyed that they were useful in gaining a clearer picture of what the Company was planning for the upcoming years.

Q How was the review structured?

A. Drawing on my experience in performing management audits, examining operations, and conducting field reviews of assets, I structured a review that investigated the items listed above using a number of management and operational audit techniques. These techniques are designed to validate that the utility has expertise, processes, and procedures that together provide a reasonable result for their customers. Our work plan called for submitting specific data requests and reviewing the Company's responses before interviews and on-site visits. We also requested interviews covering relevant areas of the Company, performed field visits to verify both the existence of an asset and to observe the condition of that asset, performed analysis of various data, and considered the reasonableness of the Company's efforts overall.

In order to verify that the processes supporting the above items are appropriate, we also examined the planning process of the Company.

TEP's Electric System Quality, Distribution System Reliability Indices and Maintenance Practices.

Q What measures did you use to examine the Company's service quality?

A. With respect to service quality, I reviewed the major outages, ACC customer complaints, and transformer failures. Summarized below is the information regarding these issues of service quality gathered from 2013 through 2015. The data responses include reports that are detailed and indicate the date, time, and duration of major outages, along with the number of customers affected and the cause of the outage. The reports also include how each outage was reported, and it is notable that some of the outages are indicated by the Company's Energy Management System and by customers "no power" calls. A review of the causes cited allowed us to discuss (during interviews) how the Company analyzes outages and responds to them over the long term.

Table 1: Service Quality Issues

Service Quality Issues	2013	2014	2015
Outage 4 hours or more affecting greater that 200 customers[1]	23	8	10
Weather	16	2	8
Equipment	5	5	1
Other	2	1	1

[1] Source: Response to STF 5.04 (Exhibit MJM-5)

	2013	2014	2015
ACC Customer Complaints (Service Outages or power Quality)[2]	4	0	1
Non - equipment related (i.e., accident/pole hit/damage by others	1		
Weather	2		1
Equipment - leaking transformer	1		

[2] Source: Response to STF 5.05 (Exhibit MJM-6)

Transformer Failures [3] - CONFIDENTIAL	2013	2014	2015
Equipment	[redacted]		
Weather			
Damage by others			
Other			
Animal			
Human error			
Customer owned			

[3] Response to STF 5.09 - Confidential (Exhibit MJM-7)

Q What conclusion did you draw from this information?

A. As the Table shows, the Company has made significant improvements in both major outages affecting 200 or more customers and in the reduction of ACC complaints. However, transformer failures have seen [redacted] Based on my review of the cryptic descriptions contained in the data, it is difficult to pinpoint whether corrective actions could be taken to address this area. I would note that many of the outages are driven by weather and storms. Restoration times (included in the following discussion) are key. Overall, based on the data I reviewed and the field inspections we conducted of the Company's facilities, I believe the Company's level of service appears reasonable.

Q What measures did you use to examine the Company's service reliability?

A. The electric utility industry uses standardized measures of outage reporting, which have been defined by the Institute of Electrical and Electronic Engineers ("IEEE") under its standard number P1366, "Guide for Electric Distribution Reliability Indices." The industry often uses the following relevant measures:

- Customer Average Interruption Duration Index ("CAIDI") is the weighted average length of an interruption for customers affected during a specified time period
- System Average Interruption Frequency Index ("SAIFI") is the average number of times that a customer's power is interrupted during a specified time period
- System Average Interruption Duration Index ("SAIDI") is the average duration of interruptions for customers served during a specified time period

The IEEE also recognizes the concept of Major Event Days ("MED"), which factors out events such as hurricanes, tornados, floods, and other events that cannot be predicted,

avoided, and/or are considered not repeating. There is a specific methodology to identify a MED arithmetically and adjust the statistics.

Generalized averages for these indices are available, but any utility's performance must be evaluated within the context of its demographic and geographic characteristics. For example, a suburban utility with a high customer density can often respond to an outage much faster than a rural utility (due to shorter travel distances) and, due to the compact configuration of its system, may have inherent redundancy and more extensive automatic equipment, which will reduce outage times. Systems with high percentages of underground equipment may have lower outage rates but may take longer to repair if an outage occurs. Conditions, such as lightning, salt spray, and birds in a utility's service territory, may also affect the indices, although the utility can address some of the impact of these conditions by engineering design standards.

Table 2: IEEE Performance Indices Benchmark Standards[15]

Performance Indices IEEE Benchmark Standards	2012	2013	2014
CAIDI - 1st Quartile	<93	<92	<91
CAIDI - 2nd Quartile	94-110	93-107	92-104
CAIDI - 3rd Quartile	111-130	108-127	105-127
SAIFI - 1st Quartile	<.89	<.85	<.86
SAIFI - 2nd Quartile	.90-1.08	.86-1.08	.87-1.07
SAIFI - 3rd Quartile	1.09-1.39	1.09-1.36	1.08-1.33
SAIDI - 1st Quartile	<93	<85	<86
SAIDI - 2nd Quartile	94-126	86-115	87-115
SAIDI - 3rd Quartile	127-163	116-158	116-159

Table 3: TEP Service Reliability Indices

Indices	2012	2013	2014	Test Year
CAIDI	74.66	92.86	80.05	80.23
SAIFI	0.93	0.68	0.71	0.66
SAIDI	69.79	63.50	57.12	53.08

[15] Institute of Electrical and Electronics Engineers (IEEE) Benchmark Year 2015, Results for 2014 Data, http://grouper.ieee.org/groups/td/dist/sd/doc/2015-09-Benchmarking-Results-2014.pdf.

With the exception of the 2012 SAIFI index and the 2013 CAIDI index, the Company's reliability indices are in the 1st quartile of performance. Based upon the data trends, size of the Company, demographic and geographical conditions, and the above statistics, the service reliability of the Company is considered reasonable.

Q Please describe your review of the maintenance practices.

A. My review was two pronged. First, I requested the Company to provide its maintenance procedures covering transmission and distribution. The Company provided a voluminous set of documents.[16] I then reviewed with Company management its expectations related to maintenance practices both in a joint meeting with Company transmission and distribution managers and operating personnel in the field. With respect to the manuals, I conducted a high-level review of the information provided on the five data disks of information. These disks contained thousands of documents covering installation and maintenance procedures for all sorts of equipment in the Company's system. While I did not determine that these procedures are readily available throughout the Company's maintenance facilities, the fact that the Company did pull this information together for this data request does provide a level of confidence that, when needed, the information is available to Company personnel. I would note that included in this information were forms that Company personnel would fill out when a preventive maintenance practice on a particular piece of equipment was performed. These forms specified what actions needed to be taken and in what intervals to effectively maintain the equipment. Included as Exhibit MJM-9, CCP Patrol Criteria is a copy of a one-page inspection procedure for the Company's distribution facilities. It is a simple form, but as noted in a footnote to the procedure, it was last revised in February 2015, obviously suggesting that someone reviewed the procedure within the last 15 months. Similarly, I have included as Exhibit MJM-10 a copy of the Company's transmission line

[16] Company response to STF 9.006 (Exhibit MJM-5)

patrol inspection procedure. The scope of our review did not include validating that these procedures are adhered to throughout the Company, but based on the comprehensive nature of the response and our observations in the field, I am reasonably confident that the Company does conduct effective maintenance of the equipment used to serve customers.

Q. Describe your review of TEP's safety strategies.

A. The Company uses a full-time "safety rover" to monitor Company crews and contractors. Weekly safety meetings are held and work-specific tailboard sessions are conducted. A Corporate Safety meeting is held monthly.

TEP characterizes its "Target Zero" safety strategy as "the essential safety policy of the company."[17] The Target Zero strategy reflects the Company's stated concern by emphasizing safety in job design, planning, communication, mutual support/teamwork, task management, situational awareness, decision making, and debriefing.[18]

Q. How does TEP compare to the industry in terms of safety?

A. The Company provided its recordable injury rate for years 2013 through 2015. The rates were 0.96, 1.67, and 0.4, respectively.[19] According to the U.S. Bureau of Labor Statistics for 2014, the rate of recordable incidences industry-wide was 2.4.[20] Therefore, the Company is well below the industry trend.

Q. How would you describe the Company's safety program?

A. Based upon the processes described and the above statistics, the safety program of the Company is considered reasonable.

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[17] TEP response to STF 5.001 (Exhibit MJM-11).
[18] TEP response to STF 5.001 (Exhibit MJM-12).
[19] Exhibit MJM-12 - TEP response to STF 5.003.
[20] Exhibit MJM-13 - TEP response STF 5.002.

The "Used and Usefulness" of Assets

Q Please describe your review of the used and usefulness of the Company's assets that it is requesting in rate base.

A. Here again, we proceeded with a two-pronged approach: a document review of random projects that were completed since the last case through the test year ending June 30, 2015, as well as projects that the Company is including in its two post-test-year plant addition adjustments—regular plant and renewables[21] and field inspection/observation of select projects. We randomly selected projects from a list of all the projects that made up the rate base additions. As part of our preparation for the field review, we developed a list of information that would be reviewed prior to going to see the facility.

Q What information did you request?

A. In a data request series, STF 6.01 – 6.25 (Exhibit MJM-14), we provided the Company with a list of 21 items of information that we wanted to be provided for 25 selected projects. From this documentation, we selected the facilities that we would visit. The checklist recorded basic information about the project, such as project number and title, whether it was included in the approved capital budget, start and end dates, justification, history of estimates, and actual cost. The checklist also included a section asking more specific questions, such as whether the assets were visible, operational, and the same as the original scope and whether Company personnel fully understood the project and identified problems during construction that either extended the work or increased costs.

Q Were you satisfied with the Company's response to this request for information about all these projects?

A. Generally, yes.

[21] The Company's post-test year plant adds where for additions through 12/31/15 while renewables would cover through 12/23/2016.

Q What were the 25 projects of which you conducted a document review?

A. The following is a list of the projects that were included in the ratebase additions from 2012 to 2014.

Table 4: Summary of Staff Reviewed Projects

TUCSON ELECTRIC POWER COMPANY
Plant In Service by Year Unitized >$2M
January 2012 through December 2014

	Blankets	$ 89,455,607.54	38.3%	6
	Non-Blanket	$ 255,792,618.05	78.3%	19
Sum of Amount Unitized	Total	$ 345,248,225.59		

CBOAD00 San Juan Repl And Bett	Blanket	31,877,987.37	5.7%	5.7%
CBOND96 Dist System Integrity	Blanket	22,965,741.59	4.1%	15.0%
CBON100 Meters & Metering Equipment	Blanket	18,312,857.53	3.3%	21.8%
CBOSK04 SGS U2 Turbine/Circ Water	Blanket	8,853,445.62	1.6%	28.3%
CBOSK01 SGS U2 Blanket	Blanket	4,664,576.30	0.8%	36.4%
CBOSH02 SGS U12 Coal Yard	Blanket	2,780,999.13	0.5%	40.2%
D12PD41 SGS 10MW Expansion	Other	46,499,098.72	8.3%	50.0%
D07BL04 Pwest-Sross Line & Sub Partcptn	Other	39,357,876.89	7.0%	57.0%
D14PD43 2014 Bright Buildout Plan Fort Huachuca	Other	32,585,361.15	5.8%	62.8%
D13SK07 SGS U2 LP1 and LP2	Other	20,245,406.58	3.6%	66.4%
D05BL01 Palo Verde-Pinal West Part	Other	19,149,811.56	3.4%	69.9%
D08BP01 Vail T3 345/138kV Xfmr Add	Other	18,315,795.88	3.3%	73.1%
D12PD38 Prairie Fire	Other	17,804,765.82	3.2%	76.3%
D12AC67 Concentrated Solar	Other	10,101,949.71	1.8%	78.1%
D14SK02 02 Boiler Outage Work	Other	7,395,505.55	1.3%	79.4%
D13HC03 Ft Huachuca 138kV Xfmr Rplc	Other	5,916,031.57	1.1%	80.5%
D09IQ02 Duval Clr 138kV Sub	Other	5,912,832.99	1.1%	81.5%
D09BB04 Can Rnch - Duval Clr 138kV Line	Other	5,861,820.22	1.0%	82.6%
D05AG01 Deming Luna Project	Other	5,503,422.96	1.0%	83.6%
D08BB76 DMP-Tucson 138kV Ln	Other	5,106,175.84	0.9%	84.5%
D10GN10 NL 138kV Yard Expansion Ph 3	Other	4,630,650.55	0.8%	85.3%
D111WMC T&D Work Mgmt Consolidation Ph1	Other	3,386,333.41	0.6%	89.6%
D14RI02 Ft Huachuca - Solar	Other	2,948,890.94	0.5%	93.0%
D13SB06 Main Access Road Construction	Other	2,829,505.64	0.5%	95.0%
D13NM12 Grant T1 46kV Sub Xfmr Replc	Other	2,241,382.07	0.4%	98.1%

As the table shows, we requested and reviewed information for over $345 million of plant additions. I would note that the Company is seeking to include $645 million of rate base additions since the last rate case.[22] From this list we selected 10 projects at which to conduct field observations. The following table is a list of those projects.

[22] TEP Application page 4 line 27.

Table 5: Projects for Field Observation

Project & Description	Type	Total 2012-14
D12PD41 SGS 10MW Expansion	Other	46,499,098.72
D07BL04 Pwest-Srosa Line & Sub Partcptn	Other	39,357,876.89
D14PD43 2014 Bright Buildout Plan Fort Huachuca	Other	32,585,361.15
D13SK07 SGS U2 LP1 and LP2	Other	20,245,406.58
D05BL01 Palo Verde-Pinal West Part	Other	19,149,811.56
D08BP01 Vail T3 345/138kV Xfmr Add	Other	18,315,795.88
D12PD38 Prairie Fire	Other	17,804,765.82
D12AC67 Concentrated Solar	Other	10,101,949.71
D13HC03 Ft Huachuca 138kV Xfmr Rplc	Other	5,916,031.57
D111WMC T&D Work Mgmt Consolidation Ph1	Other	3,386,333.41

Q What did you conclude from these field visits?

A. Based on my observations and questioning of Company personnel familiar with the projects, I found that the Company exercised adequate project management and controls on the construction activities. Company personnel were knowledgeable of the various projects and very willing to discuss issues concerning the construction and costs. Each project was completed on time and within budget. I want to express thanks to the Company personnel who coordinated our visit to the sites. They were forthcoming and candid about each project.

Q Did you visit both Gila River and Springerville Generating Stations?

A. Yes. Blue Ridge's Joe Freedman and I visited both locations along with the others. ACC Staff Candrea Allen and Matt Connolly participated in the visit to Gila River. Mr. Freedman and I drove from Gila River to Springerville on the afternoon of March 30 (about 200 miles). We met Springerville personnel on the morning of March 31, and then returned to Phoenix. All told, we covered over 800 miles of driving to conduct these field observations.

Q Did you have any concerns or questions from your field observations?

A. Yes. When we visited the Springerville Station, I noted that the SGS 10 MW expansion (a very large renewable solar project) was very remote from TEP's service area. I questioned where the output from the solar facilities was going and being used. The Company informed me that the output was used to power the deep well fields that are providing water to the station. In response to a data request (STF 13.1 – Exhibit MJM-15), the Company provided a detailed explanation of the accounting used to record and allocate the amount of solar energy produced by the solar project at the station. This documentation shows that 100 percent of the power is accounted for and that each of the four units at the station is allocated 25 percent of the MWs that come from the solar project. However, the Company could not breakout the exact amount of the benefit of the solar project to the station without substantial effort.[23] Further, the Company said the journal entry of the cost of the power was charged at the previous month's rate.[24] Which rate is used is unclear. The cost rate that should be charged for this power should reflect the Company's fully allocated cost of the production from the solar project—not the station average as I suspect is used. Obviously, not crediting customers for the full cost of the power from the solar project results in customers subsidizing energy costs to the station. I would recommend that the Company modify its accounting to ensure that the fully allocated cost of production from the solar project at the station is credited.[25]

[23] The Company said the station used power entry that comes from 22 meters located at the station and that the solar project is one of those 22 meters.
[24] Exhibit MJM-15 Response to STF 13.1
[25] I note that TEP is in the process of acquiring Unit 1.

Demand and System Energy

Q. How did you review TEP's system energy?

A. I examined the Company's total system energy for the years since the last rate case—2013 through 2015. The following chart illustrates TEP's total system energy (MWh) by month for each of the years 2013 through 2015.

Table 6: TEP Total System Energy (in MWh)[26]

	2013	2014	2015
Jan	1,133,846	1,040,001	1,159,390
Feb	1,016,329	974,897	1,019,171
Mar	1,016,470	1,023,142	1,144,397
Apr	1,027,281	989,637	1,146,794
May	1,124,216	1,087,194	1,273,712
Jun	1,321,349	1,336,809	1,444,492
Jul	1,367,161	1,453,409	1,628,787
Aug	1,353,850	1,389,535	1,659,586
Sep	1,214,982	1,296,218	1,471,780
Oct	1,149,239	1,283,116	1,303,297
Nov	1,071,563	1,135,302	1,217,171
Dec	1,117,889	1,140,266	1,297,969
Total	13,914,175	14,149,526	15,766,546

Q. What else did you examine?

A. I reviewed the Company's Monthly Peak Load on the system for the same time period. The Monthly Peak Load in megawatts is shown in the following table.

[26] TEP FERC Form 1, page 401.

Table 7: TEP Monthly Peak Load[27]

	2013	2014	2015
Jan	1,861	1,199	1,273
Feb	1,814	1,197	1,068
Mar	1,427	1,144	1,321
Apr	1,502	1,437	1,417
May	1,745	1,890	1,795
Jun	2,230	2,129	2,206
Jul	2,200	2,218	2,066
Aug	2,194	2,047	2,214
Sep	2,014	2,065	1,879
Oct	1,544	1,551	1,847
Nov	1,168	1,183	1,161
Dec	1,255	1,225	1,332

Q. Did you examine the Company's number and types of customers associated with the energy output?

A. Yes. Reflecting the same three-year period, the following chart lists both the average number of customers per year for each customer class and the megawatt hours sold to each customer class.

Table 8: MWh and # of Customers by Rate Class[28]

	2013		2,014		2015	
	MWh Sold	Ave # Cust	MWh Sold	Ave # Cust	MWh Sold	Ave # Cust
Residential	3,866,666	370,879	3,726,982	374,203	3,724,403	376,439
Commercial	2,076,546	37,050	2,169,897	38,079	2,123,607	38,252
Industrial	3,192,809	625	3,235,418	608	3,172,435	592
Lighting	32,350	939	33,057	1,858	32,624	1,857
Other Public	110,549	18				

Q. Why does 2013 have an extra customer class?

A. The prior rate case filed in 2012, was settled by Decision No. 73912, of the Commission. Prior to the rate case, the "Other Public" class was in effect. New rates became effective by

[27] TEP FERC Form 1, page 401.
[28] TEP FERC Form 1, page 154.

order of the Commission on July 1, 2013. Therefore, the table above includes the Other Public classification that was in effect for the first half of 2013.

Q. What conclusions did you draw concerning the Company's peak demand, system energy, and the number and types of customers?

A. No unusual results were found.

System Line Losses

Q. Did you examine the Company's system line losses?

A. Yes. I reviewed both the method of the Company's estimation of line losses and the actual losses in MWhs.

Q. What did you find in your examination?

A. The Company explained how they estimated losses for their 345 kV lines (2 percent), 138 kV lines (3 percent), transformer (0.3 percent), and distribution (6 percent). The total system losses were estimated to be approximately 11 percent.[29]

The following chart shows actual line losses reported in years 2013 through 2015 in megawatt hours.

Table 9: TEP Line Losses (in MWh)[30]

	2013	2014	2015
Losses			
Transmission	409,286	325,999	365,108
Distribution	464,102	498,480	444,034
Total	873,388	824,479	809,142

[29] Exhibit MJM-17 TEP response to UDR 1.001, Schedules G&H Support.
[30] Exhibit MJM-16 TEP response to STF 9.007.

Q. What did you conclude regarding the Company's system line losses?

A. No unusual results were found.

Construction / Capital Expenditures

Q. What have you observed regarding TEP's construction / capital expenditures since the last rate case?

A. Company Witness Gray briefly describes TEP's capital expenditures since the last rate case in Docket No. E-01933A-12-0291 for Transmission (T), Distribution (D), and Communications. She states that the Company invested a total of $491 million in T&D and Communications.[31] The rate of spending by year is as follows:

Table 10: Capital Expenditures Rate of Spending

	2012	2013	2014	Year to Date 2015	Total
Cap Ex ($ millions)	$130	$117	$127	$117	$491

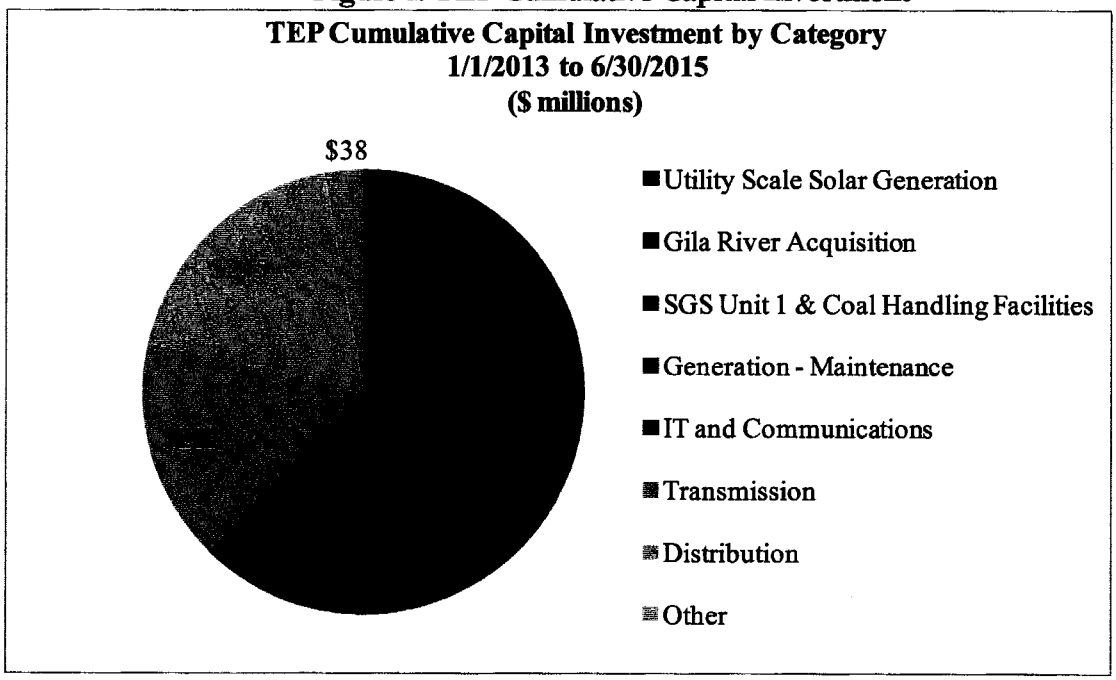
This rate denotes a clear picture of the magnitude of expenditures.

Q Please explain.

A. In reviewing Ms. Gray's workpapers, I found a Company-prepared chart that showed total Company expenditures from January 1, 2012, until June 30, 2015—the end of the test year. That chart shows capital expenditures of $1.317 billion, which includes the major acquisition costs associated with Gila River and Springerville. I present that chart below.

[31] Direct Testimony of Susan Gray at page 18, Lines 21.

Figure 1: TEP Cumulative Capital Investment



Source: UDR 1.001 – Gray Workpapers C – TEP Capital expenditures (Exhibit MJM-18)

Q Do you have any concerns regarding the rate of spending for any of these categories?

A. No. However, it is important to report one certain issue for the Commission.

Q Please continue.

A. According to the requirements of the settlement in E-01933A-12-0291, TEP agreed to meet annually with Staff to review the Company's actual capital spending and future plans for the upcoming year. Meetings with Staff were held in December 2014 and then again in December 2015. Information presented in these meetings is consistent with what the Company has overall included for recovery in current rate base. I would recommend that these meetings continue as Staff has conveyed that they were useful in gaining a clearer picture of what the Company was planning for the upcoming years.

Expenditures in Growth and Reliability Improvement

Q. Did you review TEP's planned expenditures in growth and reliability improvement?

A. Yes.

Q Please explain what you found?

A. The Company has spent $68.3 million since the last rate case on growth (i.e., new business), and $371.0 million on projects directly attributable to maintaining or improving reliability. The table below shows the rate of spending for each category.

Table 11: Improvement Expenditures

($000's)	2012	2013	2014	YTD June 30, 2015	Total
New Business	$ 16,930	$ 14,812	$ 21,709	$ 14,823	$ 68,274
System Reinforcement	$ 76,234	$ 71,212	$ 65,710	$ 82,628	$ 295,784
System Integrity & Restoration	$ 24,035	$ 24,732	$ 20,682	$ 9,769	$ 79,218

As I mentioned earlier, with the rate of spending that TEP has committed to in the past, I believe it is appropriate that the Company and Staff continue to meet annually. A free exchange of information will keep both parties from being surprised in the next case.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Michael J. McGarry, Sr. Experience and Qualifications Professional

Summary

Mr. McGarry's professional experience spans thirty-three years within the private and public sectors. He has been a project manager of numerous rate case and management audit reviews for commissions and public advocates in addition to testifying in a number of jurisdictions. He is knowledgeable and well-versed in the issues facing the energy industry with respect to renewable energy resources, alternative rate plans, cost unbundling, rate case management, and regulatory affairs. His regulatory auditing and affairs experience includes managing rate case audits and managing rate cases for commissions, attorney general offices, and consumer advocates. In addition, Mr. McGarry has conducted over 30 management and operational audits which, in most cases, evaluated management decisions and actions in light of information that was known to utility executives and managers at the time decisions were made or actions were taken. Topics of these included fuel procurement, environmental compliance strategy, customer service, renewable energy, and others.

Selected Professional Experience

Regulatory and Rate Cases

Mr. McGarry has worked with clients to manage all aspects of the regulatory and rate case process. He has developed efficient processes to prepare supporting analyses and testimony for submission to the regulatory bodies and interveners. He is a seasoned project manager and has analytical expertise to respond to interrogatories and data requests from all rate case interveners in a timely manner. Mr. McGarry has assisted a number of clients in preparing revenue requirement and cost of service analyses. He has also developed rate structure and billing determinant information analyses, time of day and interruptible rates analyses, fuel and purchased power reports, and annual wholesale rates for member cooperatives. He has developed complex revenue requirement models to present alternative positions to a utility's proposed rate request.

- On behalf of the Arizona Corporation Commission, Docket No. E-04204A-15-0142, in the matter of the application of UNS Electric, Inc. (UNSE) for the establishment of just and reasonable rates and charges designed to realize a reasonable rate of return on the fair value of the properties of UNSE devoted to its operations throughout the State of Arizona and for related approvals. April 2015-Present. Consulting Partner. Conducted analysis of components of the Company's proposed revenue requirement proforma adjustments.
- On behalf of the District of Columbia Public Service Commission (DCPSC), Formal Case No. 1106: In The Matter Of The Investigation of Washington Gas Light Company's (WGL) Interruptible Service Customer Class, the operation of WGL's Distribution Charge Adjustment, How WGL's Class Cost of Service Study Accounts For Revenues From Certain Classes Of Customers, the proper design of Interruptible Service Rates, and related issues, February 2014-present. Lead Consultant and Assistant Project Manager. Provided assistance with management of the team and schedule as well as providing support to lead consultants in their review of customer class cost of service issues.

- On behalf of the Michigan Attorney General, Case No. 17496: In the Matter of the application of Consumers Energy Company for approval of long-term power purchase auction procedures. February-April 2014. Project Manager and Testifying Witness. Reviewed the company application, other documents filed in the case, including DRs, and relevant sections of the Michigan Code of Laws in preparation for filing expert witness testimony regarding the reasonableness and prudency of the company's proposed long-term power purchase auction procedure.
- On behalf of the Georgia Public Service Commission, Docket No. 36989, Georgia Power Company's 2013 general rate case, June-November 2013. Project Manager and Testifying Witness. Led a team of consultants providing advisory services to the Commission staff with analysis of fossil fuel O&M, environmental capital cost and compliance, and transmission and distribution system costs. Provided written testimony in support of Staff's position on those issues.
- On behalf of the District of Columbia Public Service Commission (DCPSC), Formal Case No. 1103: In the Matter of the Application of the Potomac Electric Power Company (Pepco) for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service, June 2013-July 2014. Assistant Project Manager. Advised Commissioners and Staff on proposed revenue requirements, rate base, rate design, reliability projects, and cost recovery mechanism.
- On behalf of the Arizona Corporation Commission, Docket No. E-04204A-12-0504, in the matter of the application of UNS Electric, Inc. (UNSE) for the establishment of just and reasonable rates and charges designed to realize a reasonable rate of return on the fair value of the properties of UNSE devoted to its operations throughout the State of Arizona and for related approvals. April-November 2013. Project Manager and Testifying Witness. Oversaw analysis and assessment of the company's proposed cost of service and rate design, and energy efficiency mechanisms. Provided written testimony in support of Staff's position regarding energy efficiency mechanisms and cost adjustors.
- On behalf of Central Hudson Gas and Electric Corporation to provide assessment of its business case for the replacement of its legacy information systems platforms. January-March 2013. Project Manager and Lead Consultant. Provide review and comment on company testimony to be submitted in context of the Company's general rate case which seeks concurrence and/or approval of its proposed business case.
- On behalf of the Staff of the Delaware Public Service Commission, Docket No. 12-546, Delmarva Power & Light for an increase in gas base rates. February-December 2013. Project Manager and Testifying Witness. Reviewed, analyzed, and evaluated the Company's proposed gas main extension policy as to the need, cost benefits, and the equity of distribution of costs and provided expert witness testimony on those issues.
- On behalf of the Attorney General of the State of Michigan, Case No. U-15768. Detroit Edison Company. October 2012-May 2013. Project Manager and Testifying Witness. Supported the Attorney General of the State of Michigan (MIAG) with analysis and/or testimony. Issues included: prudency of AMI investments, expenses,

and cost/benefits; partial and interim rate relief; acquisitions; revenue requirements; revenue decoupling; cost of service; revenue allocation; and rate design.

- On behalf of the Staff of the Arizona Corporation Commission, Docket No. 12-0291: Application of Tucson Electric Power Company for Just and Reasonable rates and charges to realize a reasonable rate of return in Arizona, before the AZCC. August 2012-June 2013. Project Manager and Testifying Witness. Oversaw analysis and assessment of the company's proposed cost of service and rate design, cost of capital and return on equity, and energy efficiency mechanisms. Provided written testimony in support of Staff's position regarding energy efficiency mechanisms and environmental compliance adjustor.
- On behalf of the District of Columbia Public Service Commission (DCPSC), Formal Case No. 1093: In the Matter of the Investigation into the Reasonableness of Washington Gas Light Company's (WGL) Existing Rates and charges for Gas Service. July 2011-July 2013. Assistant Project Manager and Lead Consultant. Participated on a team of consultants providing advisory services to Commissioners and Staff on proposed revenue requirements, rate base, and rate design. Team analyzed revenue requirements, fuel costs, uncollectibles, environmental issues affecting rate base, inventory adjustments, plant in service, construction work in progress, research and development issues, safety initiatives, affiliate allocations, and energy funds.
- On behalf of the Staff of the DEPSC, Docket No. 11-528: in the matter of the application DPL for approval of modifications to its electric base rates, January-July 2012. Project Manager. Oversaw rate case analysis and assessment of company's proposed inter-company allocations.
- On behalf of the District of Columbia Public Service Commission (DCPSC), Formal Case No. 1087: In the Matter of the Application of the Potomac Electric Power Company (Pepco) for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service, September 2011-December 2012. Project Manager and Lead Consultant. Advised Commissioners and Staff on proposed revenue requirements, rate base, rate design, reliability projects, and cost recovery mechanism.
- Before the Arizona Corporation Commission, Docket No. 11-0224, Arizona Public Service Company Rate Case, July 2011-March 2012. Project Manager and Testifying Witness. Analyzed the Company's proposed Infrastructure Tracking Mechanism, power supply adjustor, and tariffs. Testimony filed in November 2011.
- On behalf of the North Dakota Public Service Commission (NDPSC), Case No. PU-10-657/PU-11-55: Northern States Power Company (NSP) 2011 and 2012 Request for Authority to Increase Electric Rates in North Dakota, April-October 2011. Project Manager and Testifying Witness. Led a team of consultants engaged to review NSP's proposed adjustments, rate base, revenues and expenses, affiliate transactions and allocations, revenue requirement, cost of capital, and cost of service and rate design. Evaluated NSP's proposed revenue requirement and testified before the NDPSC to proposed adjustments to the revenue requirements filed by the company in its application.

- On behalf of the City of Kansas City, Case No. HR-2011-0241: Veolia Energy Company (Veolia) 2011 and 2012 Request for Authority to Increase Electric Rates in Missouri, July-September 2011. Project Manager and Testifying Witness. Led a team of consultants engaged to review Veolia's proposed adjustments, rate base, revenues and expenses, affiliate transactions and allocations, revenue requirement, cost of capital, and cost of service and rate design. Evaluated Veolia's proposed revenue requirement and testified before the Missouri Public Service Commission to proposed adjustments to the revenue requirements filed by the company in its application.
- On behalf of the Attorney General of the State of Michigan (MIAG), Case No. U-16472: In the matter of the application of Detroit Edison for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority, February 2011-April 2014. Project Manager and Testifying Witness. Review of Advanced Metering Infrastructure program cost benefits and tariffs filed and testifying witness to same.
- On behalf of the CTPURA, Docket #10-02-13: Application of Aquarion Water Company to Amend its Rate Schedules, April-August 2010. Project Manager. Oversaw rate case analysis and assessment of company's proposed revenue requirement specifically related to cash working capital and test year expenses. Assisted with analysis of specific issues and preparation of Commission's recommended decision.
- On behalf of the Staff of the DEPSC, Docket No. 09-414: in the matter of the application of DPL for approval of modifications to its electric base rates, September 2009-May 2010. Project Manager. Oversaw rate case analysis and assessment of company's proposed revenue requirement. Assisted with analysis of specific issues and preparation of witness testimony.
- On behalf of the DCPSC, Formal Case No. 1076: In the Matter of the Application of Pepco for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service, July 2009-June 2010. Project Manager. Advised Commission Staff on the Company's and intervener's filings and testimony regarding revenue requirements, rate base, cost of service, rate design, bill stabilization, and depreciation.
- On behalf of the UTDPU, Docket No. 09-035-23: In the Matter of the Application of RMP for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, June 2009-February 2010. Project Manager and Testifying Witness. Verified the reasonableness of the revenue requirements as provided by the company in its application and testified before the Public Service Commission of Utah.
- On behalf of the Staff of the Maryland Public Service Commission (MDPSC), Case No. 9092/9093 (Phase II): Base Rate Proceeding for Pepco and DPL, December-March 2008. Project Manager and Testifying Witness. Provided rebuttal testimony on behalf of the Commission related to the reasonableness of the costs and charges of Pepco Holdings, Inc. Service Company.

- On behalf of the Ohio Hospital Association, Case No. 08-0917-EL-SSO: In the matter of the Application of American Electric Power of Ohio for authority to increase rates for distribution of electric service. Provided expertise to the association's attorney in negotiating rate with American Electric Power, September 2008-March 2009. Evaluated revenue and rate impact on member hospitals.
- On behalf of the MIAG, Case No U-15244: In the matter of the application of Detroit Edison (DetEd) for authority to increase its electric base rates, September 2007-October 2008. Project Manager and Testifying Witness. Testified regarding revenue requirements.
- On behalf of the Ohio Schools Council, Case No. 07-0551-EL-UNC: In the matter of the Application of FirstEnergy Ohio (and its operating companies Ohio Edison, Cleveland Electric, and Toledo Edison) for authority to increase rates for distribution service, modify certain accounting practices and for tariff approval, August 2007-April 2008. Project Manager. Hired by Ohio Schools Council's attorney for utility matters (Bricker and Eckler, LLP) to provide industry expertise in reviewing FirstEnergy's application with respect to cost of service and rate design and the resulting impact on Council's member school systems' energy costs.
- On behalf of the MIAG, Case No. U-15245: In the matter of the application of Consumers Energy Company (CECO) for authority to increase its rates for the generation and distribution of electricity and for other relief, July 2007-April 2008. Project Manager and Testifying Witness. Provided expert testimony on partial and interim rate relief, CECO's decision to acquire Zeeland Power Company from Broadway Gen Funding, LLC. Provided testimony in permanent phase to reduce company's net operating income to more closely reflect the expected costs in 2008.
- On behalf of the City of Cincinnati, Case No. 06-0986-EL-UNC: In the matter of the Application of Duke Energy Ohio, Inc., to modify its market-based standard service offer, May-August 2007. Project Manager. Hired by City of Cincinnati's Water and Sewer District attorney for utility matters (Bricker and Eckler, LLP) to provide industry expertise in reviewing the Company's proposal and impact on City's project energy costs.
- On behalf of the MIAG, Case No U-15190: In Base Rate Proceeding for CECO, March-September 2007. Project Manager. Reviewed the revenue decoupling proposal and supported the witness testimony.
- Technical consultant for the DCPSC in the matter of Pepco's request for a $50.4 million increase in base rates (Formal Case No. 1053), February 2007-June 2008. Project Manager. Provide technical expertise to Commission in evaluating the Company's rate case filing. Commission accepted adjustments which reduced the allowed increase by a significant percentage.
- On behalf of the Staff of the MDPSC, Case No. 9092: Base Rate Proceeding for Pepco, January-June 2007. Project Manager. Reviewed and analyzed company's base increase request and all pro formas, adjustments to test year revenue requirement and supported witness testimony. Commission approved less than 20% of Company's original request.

- On behalf of the Consumer Advocate of the Province of Nova Scotia, Case No. P-888: Base rate proceeding of Nova Scotia Power, December 2006-March 2007. Project Manager and Testifying Witness. Provided an evaluation of a management audit of Nova Scotia Power and that report's usefulness to assess the Company's management performance and operational efficiency within the context of that proceeding.
- On behalf of the Staff of the DEPSC, Docket No. 06-284: in the matter of DPL's request for a $15M increase in gas base rates, October 2006-March 2007. Project Manager and Testifying Witness. Testified on several rate base and revenue requirement issues. Recommended Commission reduce proposed rate increase request to $8.4M (56%).
- On behalf of the Staff of the MDPSC, Case No. 9062: In the matter of the application of Chesapeake Utilities Corporation for authority to revise its rates and charges for gas service, May-October 2006. Project Manager. Managed a project team responsible for providing expert witness testimony in the areas of revenue requirements, rate base, cost of service, revenue allocation, rate design, revenue normalization, and cost of capital.
- On behalf of the MIAG, Case No. U-14547: In the matter of the application of CECO for authority to increase rates for the distribution of natural gas and for other relief, December 2005-April 2006. Expert Witness and Project Manager. Provided analysis, recommended adjustments, and filed testimony for the Attorney General on CECO's proposed increase to base rates.
- On behalf of the Illinois Citizens Utility Board, Cook County State's Attorney's Office and City of Chicago, Case: 05-0597, November 2005-May 2006. Project Manager and Testifying Witness. Provided analysis and recommended adjustments in the general rate increase of 20.1% or $320 million filed by Commonwealth Edison Company.
- On behalf of the MIAG, Case No. U-14347. Consumers Energy Company. April-September 2005. Project Manager. Supported the MIAG with analyses in preparation for testimony before the Commission.
- On behalf of the DCPSC, Formal Case No. 1032: In the Matter of the Investigation into Pepco's Distribution Service Rates, January-March 2005. Project Manager. Review and evaluation of Pepco compliance filings for class cost of service and revenue requirements for distribution service pursuant to a settlement approved in May 2002. Provided analysis and recommended adjustments to Staff on 23 designated issues and 13 Company proposed adjustments. Proceeding was settled in anticipation of a full rate case for rates to be effective August 8, 2007.
- On behalf of the DCPSC, Formal Case No. 1016: In the Matter of the Application of Washington Gas Light Company (WGL), District of Columbia Division, for Authority to Increase Existing Rates and Charges for Gas Service, June-December 2003. Project Manager and Consultant to Commissioners and Staff. Project Manager for the analysis of WGL's rate filings. Provided analysis and recommended adjustments to the DCPSC Staff on WGL's proposed increase to base rates. Advised

the Commission during deliberations on party positions and possible recommendations.

- Consultant to Ameren UE. Conducted revenue requirement analysis in preparation of Missouri Public Service Commission compliance filing to un-bundle utility's rate tariffs. Prepared the filing requirements and all support schedules analysis to justify allocations of generation, transmission and distribution.
- Advised South Carolina State Senator on regulatory process for requesting States Public Service Commission for a comprehensive review of Duke Power Company's storm and restoration and right of way management. Reviewed and advised Senator of results of report finding.
- NYPSC, Case: 97-M-0567, Commission Staff. Litigated proceeding to determine the benefits of a proposed merger of LILCO/Brooklyn Union Gas. Analyzed proposed synergy savings.
- NYPSC, Case: 96-E-0132, Show Cause Proceeding Regarding Rate Relief for Ratepayers of LILCO, Commission Staff and Testifying Witness. Litigated proceeding where Staff proffered testimony containing a benchmark study showing that LILCO's operations and maintenance expenses were excessive compared to a peer group of 24 utilities. Panel testimony concerning the findings and conclusions resulting from the benchmark study.
- Before the Hawaii Public Utilities Commission, Docket No. 05-0075: In the matter of a proceeding to investigate Kauai Island Utility Coop's Proposed Revised Integrated Resource Plan and Demand Side Management Framework, June-November 2005. Project Manager. Managed a team of consultants responsible for evaluating the impact of the changes proposed by the Company.

Cost Allocation, Cost of Service, and Rate Design

- MPSC Case No. U-17688, on behalf of the Michigan Attorney General in the matter of the MPSC's own motion to commence a proceeding to implement certain recently enacted provisions of Public Act 169. October 2014 to present. Project Manager and Testifying Witness. Analyzed and testified before the Commission regarding Consumer Energy's application with respect to proposed changes to cost allocation methodologies among various customer classes and rate design methods
- MPSC Case No. U-17689, on behalf of the Michigan Attorney General in the matter of the MPSC's own motion to commence a proceeding to implement certain recently enacted provisions of Public Act 169. October 2014 to present. Project Manager and Testifying Witness. Analyzed and testified before the Commission regarding DTE Energy Company's application with respect to proposed changes to cost allocation methodologies among various customer classes and rate design methods.

Hedging

- On behalf of the Public Advocate for the State of Nebraska in the matter of Black Hills Energy/NE's application to implement a long term hedge using a cost of

service approach for up to 50% of the firm demand of Nebraska customers (Docket No. NG-0086). Testified before the Nebraska Public Service Commission on the concerns of moving to a cost of service approach including shifting of risk of excessive costs to ratepayers, the inability of the Commission and Public Advocate to have the expertise to provide adequate oversight of an un-regulated business venture (i.e., gas well drilling and production), and inappropriate cost of capital and debt structure to be applied to calculation of costs to be charged ratepayers.

- On behalf of the Vermont Public Service Department in the matter of the review of filings made by Vermont Gas Systems (VGS) pursuant to its Alternative Regulation Plan, September 2013-2015. Project Manager. Led a team of consultants in reviewing VGS's hedging and benchmarking information to ascertain company practices and provide recommendations to improve strategy and credit risk level.
- Before the Utah Division of Public Utilities (UTDPU), Docket No. 09-035-15: In the Matter of the Application of Rocky Mountain Power (RMP) for Approval of its Proposed Energy Cost Adjustment Mechanism (ECAM) - Net Power Cost Evaluation (NPC), RMP 2009 General Rate Case, July-December 2009. Project Manager and Testifying Witness. Analyzed the reasonableness and technical accuracy of the RMP's NPC request, performed a comprehensive review of the Company's NPC estimate and developed recommendations to ensure an accurate baseline for the ECAM, analyzed special issues addressed in the NPC portion of the case, analyzed the Company's fuel price hedging policies and provided recommendations appropriate for the ECAM, and reviewed intervener NPC issues as well as analyzing additional issues as raised by the Company and testified to hedging issues.
- On behalf of the Staff of the Delaware Public Service Commission (DEPSC), Docket No. 07-239F: In the matter of the application of Delaware Power & Light (DPL) for approval of modifications to its gas cost rates, October 2007-April 2008. Project Manager and Testifying Witness. Oversaw review of DPL gas hedging program.
- On behalf of the Staff of the DEPSC, Docket No. 06-287: In the matter of Chesapeake Gas Corporation's implementation of a Gas Hedging program, June-August 2007. Project Manager. Provided industry expertise and suggestions to the Commission on a proposal plan to implement a gas hedging procurement program at the Company.

Power, Fuel & Gas Cost Recovery

Supported the Michigan Attorney General (MIAG) with analysis and/or testimony in Power Supply (PSCR) and Gas Cost Recovery (GCR) cases. Issues included: prior year under-recovery of power supply costs, under-recovery of cumulative Pension Equalization Mechanism costs, over-refund of the companies' residual Self-Implementation Refund, the companies' claimed credit to PSCR costs related to credit claimed by affiliate, regulatory asset recovery surcharges asset and liability balance resulting in over recovery, Reduced Emissions Fuel (REF) prudency and calculation of REF impacts, generation dispatch and purchased power, purchased power agreements, emission control expenses including appropriateness of mercury filter expenses and coal refinement expenses,

transfer price for renewable energy sources, replacement power costs, inclusion of excess fuel and variable O&M expenses proffered by various intervenors, Karn 1 outage delay and Rate E-1 discount recovery, and hedging on gas procurement.

- Case No. U-17095-R. Consumers Energy Company 2013 PSCR Plan reconciliation. July-November 2014. Project Manager and Testifying Witness.
- Case No. U-17097-R. Detroit Edison Company 2013 PSCR Plan reconciliation. July-Nov 2014. Project Manager and Testifying Witness.
- Case No. U-17319. Detroit Edison Company 2014 PSCR Plan. February-August 2014. Project Manager and Testifying Witness.
- Case No. U-16892-R. Detroit Edison Company 2012 PSCR Plan reconciliation. May-December 2013. Project Manager and Testifying Witness.
- Case No. U-17097. Detroit Edison Company 2013 PSCR Plan. February-April 2013. Project Manager and Testifying Witness.
- Case No. U-16434-R. Detroit Edison Company 2011 PSCR Plan reconciliation. June 2012-February 2013. Project Manager and Testifying Witness.
- Case No. U-16892. Detroit Edison Company 2012 PSCR Plan. November 2011-May 2012. Project manager and Testifying Witness.
- Case No. U-16047-R. Detroit Edison Company 2010 PSCR Plan reconciliation. August 2011-March 2012. Project Manager and Testifying Witness.
- Case No. U-16432. Consumers Energy Company 2011 PSCR Plan. February-June 2011. Project Manager.
- Case No. U-16434. Detroit Edison Company 2011 PSCR Plan. February-June 2011. Project Manager and Testifying Witness.
- Case No. U-15675-R. Consumers Energy Company 2009 PSCR Plan reconciliation. October 2010-January 2011. Project Manager and Testifying Witness.
- Case No. U-15677-R. Detroit Edison Company 2009 PSCR Plan reconciliation. September-December 2010. Project Manager and Testifying Witness.
- Case No. U-16047. Detroit Edison Company 2010 PSCR Plan. January-May 2010. Project manager and Testifying Witness.
- Case No. U-15415-R. Consumers Energy Company 2008 PSCR Plan reconciliation. May-November 2009. Project Manager and Testifying Witness.
- Case No. U-15677. Detroit Edison Company 2009 PSCR Plan. January-June 2009. Project Manager.
- Case No. U-15415. Consumers Energy Company 2008 PSCR Plan. January-March 2008. Project Manager.
- Case No. U-15320. Midland Cogeneration Venture Limited Partnership (MCV) elimination of "availability caps" which limit Consumers Energy Company's recovery of capacity payments with respect to its power purchase agreement with MCV. October 2007-June 2008. Project Manager.
- Case No U-15040. Michigan Gas Utilities Corporation 2007/08 GCR Plan. March-August 2007. Project Manager and Testifying Witness.
- Case No. U-15001. Consumers Energy Company 2007 PSCR Plan. November 2006-August 2007. Project Manager and Testifying Witness.
- Case No. U-14701-R. Consumers Energy Company 2006 PSCR Plan reconciliation. June-November 2007. Project Manager and Testifying Witness.

Audits - Utility Management and Operational

Mr. McGarry has conducted comprehensive management and operational audits of investor-owned energy, telecommunications, and water utilities, including audits on most functions within the utility environment including affiliates transactions, capital and operating budget processes and practices, crew operations, commodity trading, construction program practices, corporate governance, demand side management, distribution operations and maintenance, fuel procurement, internal auditing, strategic planning, and supply chain management.

- On behalf of the Connecticut Public Utilities Regulatory Authority, Diagnostic Management Audit of all functions of Yankee Gas Services Company. June 2014-present. Co-Project Manager.
- On behalf of the Maine Public Utilities Commission. Management audit of Central Maine Power Company's (CMP) Advanced Metering Infrastructure (AMI) project in Docket No. 2013-00168, September 2013-April 2014. Project Manager. Led team of consultants to assess the effectiveness of Central Maine Power Company's AMI project management, compliance with Commission directives, the estimated versus actual cost and savings, and the program's capabilities.
- On behalf of the Public Advocate of Nebraska, Nebraska PSC. Assistant Project Manager. Supported the Public Advocate with a review of the adjustment to customer charges to reflect the company's infrastructure system replacement cost recovery charge.
    - NEPSC Application No. NG-0074, Black Hills/Nebraska Gas Utility Company, LLC, d/b/a Black Hills Energy, July-November 2013.
    - NEPSC Application No. NG-0072, SourceGas Distribution, LLC, March 2013-May 2013.
- On behalf of the Staff of the Public Utilities Commission of Ohio (PUCO). Assistant Project Manager. Participated on a team of consultants engaged to review and ensure the accuracy and reasonableness of the Companies' compliance with its Commission-approved infrastructure cost recovery rider filings. The review included a detailed mathematical verification and validation of the support of the riders' revenue requirements model, development of sensitivity analysis that supported the PPS sampling techniques used to isolate specific plant work order for further testing.
    - Case No. 12-2855-EL-RDR: Delivery Capital Recovery (DCR) Rider Audit of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively, Companies), December 2012-July 2013.
    - Case No. 11-5428-EL-RDR: DCR Rider Audit of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively, Companies), November 2011-May 2012.
- On behalf of the Massachusetts Department of Public Utilities, Case No. D.P.U. 08-110: Regarding the Petition and Complaint of the Massachusetts Attorney General for an Audit of New England Gas Company, February-August 2010. Project

Manager. Managed a project team of accountants and industry specialists who were responsible for evaluating the accuracy of the accounting records, practices and procedures used in the development of the Company's revenue requirements calculations in the Company's base rate request.

- On behalf of the Staff of the Public Utilities Regulatory Authority of Connecticut Docket (CTPURA) #07-07-01 Diagnostic Management Audit of Connecticut Light & Power Company, July 2008-June 2009. Project Manager. Performed overall day to day project management responsibilities to conduct a diagnostic management audit of the Connecticut Light & Power Company (CL&P). Managed a project team of accountants, engineers and industry specialists who were responsible for evaluating the effectiveness of the management and operations of all aspects of the company. In addition, managed a focused prudency review of Northeast Utilities' (CL&P's parent company) development and implementation of a $122M customer information system known as CustomerCentral or C2.
- On behalf of the Staff of the Public Utilities Commission of Ohio. Project Manager. Oversaw multi-discipline team of accountants, auditors, engineers and analysts to conduct a comprehensive rate case audit of the Company's gas base rate filing. Primary goal of project was to validate information in filing, provide findings conclusions and recommendations concerning the reliability of information and data in the filing and support Staff in its evaluation of the reasonableness of the filing.
  - Case #08-0072-GA-AIR: Columbia Gas of Ohio, April-August 2008
  - Case #07-0829-GA-AIR: Dominion East Ohio, November 2007-July 2008
  - Case #07-0589-GA-AIR: Duke Energy Ohio, November 2007-Februrary 2008
- Co-sponsored between NW Natural, Oregon Public Utilities Commission (ORPUC) Staff, Northwest Industrial Gas Users, Citizens Utility Board, Docket No. UP205: Examination of NW Natural's Rate Base and Affiliated Interests Issues, August 2005-January 2006. Project Manager. Led a team that conducted a management audit of NW Natural Gas that included an evaluation of rate base issues for Financial Instruments (gas and financial hedging) Deferred Taxes, Tax Credits, Cost for a Distribution System, Security Issuance Costs and AFUDC calculations as well as Affiliate Transactions for Cost Allocations and Transfer Pricing, Labor Loading, Segregation of Regulated Rate Base and Subsidiary Investments and Properties, and validation of tax paid from/to affiliates are proper. Audit was to ensure Company compliance with orders, rules and regulations of the ORPUC, with Company policy and with Generally Accepted Accounting Principles.
- Consultant. As part of a team that conducted a comprehensive management audit of the management and operations of Southern Connecticut Gas, completed the capital budgeting area of the audit.
- Focused review of the preparedness of Rochester Gas and Electric (RG&E) and Consolidated Edison (ConEd) for competition in the electric industry. Evaluated all aspects of the company's management actions to prepare for competition including strategic planning, goals and objectives and senior management's attention to the company operations in a de-regulated industry

- New York Public Service Commission (NYPSC), Case 93-E-0918: Operational Audit of the Demand Side Management Function at RG&E, Commission Staff. Comprehensive operational audit of the demand side management function including program planning, management and energy savings verification. Developed and supervised the implementation of the work plan.
- NYPSC, Case 92-W-0030: Operational Audit of Jamaica Water Operations and Management, Commission Staff. Comprehensive management audit of company operations. Responsible for work plan development, and specific topics areas including engineering, contracting, and information technology. Findings led to prudence proceeding.
- NYPSC, Case 92-M-0973: Management Audit of RG&E, Commission Staff. Comprehensive management audit of company operations. Responsible for work plan development, supervision of staff and specific topics areas including purchasing and internal controls.
- NYPSC, Case 91-C-0613: Operational Audit of the Outside Plant Construction and Rehabilitation Program of New York Telephone Company, Commission Staff. Comprehensive operational audit of the company's management and implementation of a $150M capital program to rehabilitate the outside plant distribution network. Served as Staff Examiner responsible for crew supervision, goals monitoring, contractor oversight, and report preparation.
- NYPSC, Operational Audit of the Fuel Procurement and Contracting of Long Island Lighting Company (LILCO), Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project.
- NYPSC, Operational Audit of the Fuel Procurement and Contracting of ConEd, Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project
- NYPSC, Case 90007: Operational Audit of the Fuel Procurement and Contracting of Central Hudson Gas and Electric, Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project
- NYPSC, Operational Audit of Fuel Procurement and Contracting of Orange & Rockland Utilities, Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project
- NYPSC, Operational Audit of the Fuel Procurement and Contracting of RG&E, Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on nuclear fuel. Provided research and data evaluation expertise.
- NYPSC, Case 88005: Operational Audit of Materials and Supply Function at National Fuel Gas, Commission Staff. Comprehensive operational audit of the

materials and supplies function including warehouse operations, inventory control and procurement. Developed and implemented the work plan for this project.

- NYPSC, Case 87003: Operational Audit of the Homer City Coal Cleaning Plant (HCCCP), Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on the construction of the HCCCP jointly owned by New York State Electric and Gas (NYSEG) and Penelec. Responsible for fuel and construction costs analysis, benchmarking costs and alternative methods for meeting EPA Clean air restrictions, contracting practices and report preparation.
- NYPSC, Case 87003: Operational Audit of the Fuel Procurement and Contracting of NYSEG, Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Responsible for fuel cost analysis, benchmarking costs, contracting practices and report preparation.
- NYPSC, Case 86007: Operational Audit of the Field Crew Supervision and Utilization of NYSEG, Commission Staff. Comprehensive operational audit to determine effectiveness of field crew utilization and supervision. Staff examiner responsible for verifying supervisor activities, reporting, goals attainment and report preparation.
- NYPSC, Case 86005: Operational Audit of the Fuel Procurement and Contracting of Niagara Mohawk Power Company (NIMO), Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Responsible for fuel cost analysis and benchmarking costs, contracting practices and report preparation.
- NYPSC, Case 85001: Operational Audit of the Research and Development Function of ConEd, Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on R&D activities. Staff examiner on the project responsible for reviewing projects documentation and control, outside contracting a report preparation.

Natural Gas Cast Iron Main Replacement

- On behalf of the MIAG, Case No. U-16407: In the matter of the application of Michigan Consolidated Gas Company (MichCon) for approval of a detailed plan for gas main renewal, including a long-term plan to significantly reduce the amount of cast iron main in its system. Nov 2010-May 2011. Project Manager and Testifying Witness. Reviewed Company's proposed plan with respect to whether a cost recovery mechanism can be designed to minimize the impact on ratepayers. Testified as to the reasonableness of cost benefit of replacements as well as to the capital cost recovery as it affects future rate cases.
- On behalf of Maine Public Advocate (MeOPA), Case No. 2008-151: Maine Public Utilities Commission (MEPUC) Investigation into Maintenance and Replacement Program for Northern Utilities Inc.'s (NUI) Cast Iron Facilities (Phase II), July 2008-July 2010. Project Manager and Testifying Witness. Litigated proceeding and led a consultant team to assist the State of Maine Public Advocate to follow-up on

investigation for the need for the program and the Company's management of the repair or replacement of its cast iron facilities.

- On behalf of MeOPA, Case No. 2004-813: MEPUC Investigation into Maintenance and Replacement Program for NUI's Cast Iron Facilities (Phase I), November 2004-March 2005. Project Manager and Testifying Witness. Litigated proceeding and led a consultant team to assist the MeOPA to investigate the need for the program and the company's management of the repair or replacement of its cast iron facilities.

Project Management

- Mr. McGarry's experience includes management of multi-discipline teams for a wide range of client engagements, development and implementation of detailed work plans and project schedules. He has analyzed and planned interdivisional resource utilization; supervised, developed and coached interdivisional team members; and created numerous executive reports, briefings, and presentations.

Prudence Reviews

- On behalf of the Staff of the Public Utilities Regulatory Authority of Connecticut Docket #07-07-01 Diagnostic Management Audit of Connecticut Light & Power Company (CL&P), July 2008-June 2009. Project Manager. Performed overall day to day project management responsibilities, within the context of a diagnostic management audit, to conduct a focused prudency review of Northeast Utilities' (CL&P's parent company) development and implementation of a $122M customer information system known as CustomerCentral or C2, including managing a project team of accountants, engineers and industry specialists who were responsible for evaluating the effectiveness of the management and operations of C2.
- NYPSC, Case 96-M-0858: Prudence Investigation into the Scrap Handling Practices in the Western Division of NIMO, Commission Staff and Testifying Witness. Litigated proceeding as a result of allegations of bribery and corruption in company practices related to a specific vendor who purchased company scrap metal. Led team of 10 staff examiners to quantify the extent to which the Company paid excessive rates to this vendor. Testified to the findings of the analysis. Case settled with ratepayers receiving a credit to bills
- NYPSC, Case 91-W-0583: Prudence Proceeding of the Operations and Management of Jamaica Water, Commission Staff and Testifying Witness. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive costs to rate payers. Testified on a Staff panel to the excessive costs associated with management's inattention to sound business practices related to the design, purchase and installation of the Company customer information system.
- NYPSC, Case 88-E-115: Prudence Proceeding to Investigate the Construction Costs Associated with the HCCCP, Commission Staff and Testifying Witness. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive construction charges related to the

HCCCP. Testified on a Staff panel to the fuel price differential costs resulting from the failure of the coal cleaning plant to function as designed as well as surrebuttal testimony on the cost of a flu-gas de-sulfurization plant and ancillary equipment and facilities. Case settled. Customers received $125M credit.

- NYPSC, Case 86005: Prudence Proceeding to Investigate the Fuel Procurement and Contracting Practices at NIMO, Commission Staff. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive fuel charges to customers. Responsible for fuel cost analysis and benchmarking costs, contracting practices, and testimony preparation. Case settled with customers receiving $66M credit.

Renewable Energy and Energy Conservation

- On behalf of the MIAG. Project Manager and Testifying Witness. Supported the MIAG with analysis and/or testimony regarding the Michigan Public Service Commission's 21st Century Energy Plan Report including various cases regarding Renewable Energy Plan (REP) costs and their associate plan reconciliations and Energy Optimization Plans (EOP). Analyzed cost methodologies used by the companies for adherence to approved processes and reasonable and prudent costs. Issues included calculation of transfer costs for inclusion in power supply recovery costs and adherence to specifications of Public Acts.
  - Case No. U-16655. Consumers Energy Company (CECO) reconciliation of its REP costs associated with the plan approved in Case No. U-15805 and Case No. U-16543. September 2012-January 2013.
  - Case No. U-16656. Detroit Edison Company (DetEd) reconciliation of its REP costs associated with the amended plan approved in Case No. U-16582. September 2012-March 2013. Project Manager and Testifying Witness.
  - Case No. U-16300. CECO for authority to reconcile its renewable energy plan costs associated with the plan approved in Case No. U-15805, November 2010-January 2011.
  - Case No. U-16356. DetEd for authority to reconcile its REP costs associated with the plan approved in Case No. U-15806-RPS, October 2010-March 2011.
- Independent Third-Party Evaluation of Puget Sound Energy's (PSE) Conservation Incentive Mechanism (ECIM) under the co-direction of PSE and the Washington Utilities and Transportation Commission Staff, Phase I: July-October 2009; Phase II: October 2009-September 2010. Project Manager. Assess the extent to which the design and implementation of the incentive mechanism addressed key issues and objectives required by the Commission: accuracy of implementation in calculations of incentives or penalties, compliance with the conditions and requirements of the pilot program, proper use of the calculation methodology, and which assumptions or methods were used to calculate and verify the savings report.
- On behalf of the MIAG, Case No. U-15806/U-15890: In the matter of DetEd's and MichCon's compliance with Public Acts 286 and 296 regarding their REP and

Energy Optimization Plan (EOP), March-June 2009. Project Manager and Testifying Witness. Reviewed the EOPs of both DetEd and MichCon and provided analysis of issues and shortcomings concerning the plans in relation to the specifications of the Act and the benefit to customers.

- On behalf of the MIAG, Case No. U-15805/15889: In the matter of CECO to comply with Public Acts 286 and 295 regarding its REP and EOP, March-June 2009. Project Manager and Testifying Witness. Reviewed the EOP of CECO and provided analysis of issues and shortcomings concerning the plans in relation to the specifications of the Act and the benefit to customers.

Restructuring and Unbundling

Mr. McGarry has developed the supporting analyses and regulatory filing requirements needed to support unbundling rates for utilities. This has included detailed studies where the company's plant-in-service and depreciation reserve was allocated to each unbundled function. He has assessed utility management actions to prepare the company for competition, including the processes and practices used by the utility to prepare to enter new markets and offer new services.

- Consultant to Illinois Power Company. Conducted mandated compliance filing to un-bundle utility's rate tariffs. Prepared filing requirements and all support schedules analysis to justify allocation of generation, transmission and distribution. Prepared testimony on behalf of the Company's Controller.
- Consultant to Illinois Power Company. Prepared 2001 required update filing for the ILCC compliance filing to un-bundle utility's rate tariffs. Prepared filing requirements and all support schedules analysis to justify allocation of generation, transmission and distribution. Prepared testimony on behalf of the Company's Controller.

Specialty Cases

- Case No. U-17429 on behalf of the Michigan Attorney General in the matter of the application of Consumers Energy Company for approval of a Certificate of Necessity for the Thetford Generating Plant pursuant to MCL 460.6s and for related accounting and ratemaking authorizations, September 2013-February 2014. Project Manager and Testifying Witness. Managed review and assessment of company and intervenor testimony regarding its need for generated power, the suitability of proposed new plant, reasonableness of the estimated costs and financing for the proposed plant, and the company's compliance with Commission directives related to the new plant. Testified to the best option for meeting power needs as well as the appropriateness of the contingency the Company has included in its estimated costs.
- Case No. U-17026 On behalf of the MIAG in the matter of the application of Indiana Michigan Power Company for a certificate of necessity pursuant to MCL 460.6s and related accounting authorizations, June-September 2012. Project Manager. Managed review of certificate of necessity, evaluation of company's prudency in obtaining alternative power supply options, and review of the company's

implementation of and prudency in management of its nuclear plant Life Cycle Management project in comparison to industry standards.

Telecommunications

- Before the NYPSC, Case: 94-C-0657, Commission Staff. Proceeding to evaluate the compliance of NYNEX with Commission rules and orders related to operational support system costs to competitors. Part of staff panel to facilitate discussion between company and potential competitors (i.e., users of operational support systems) and report back to Commission.
- NYS PSC Opinion: 92-36 Operational Audit of New York Telephone Company Service Quality Standards Measurement Practices. A comprehensive operational audit to assess whether the Company had effective and accurate means to measure its performance for each of eleven service quality standards; whether New York Telephone accurately reported its performance on each of the eleven service quality standards; examined the internal controls the Company had in place to ensure that its performance for each of the service quality standards were accurately measured and reported; and reviewed the then current regulations and service quality standards against the Company's actual practices and performance to determine whether regulatory changes were necessary.

Testimony and Witness Preparation

Mr. McGarry has proffered and/or supported testimony in many jurisdictions. These proceedings have included testimony involving management decisions and prudence impacts, operations and maintenance expenses, capital investments, revenue requirements, project management, and others.

Testimony proffered

Before the Arizona Corporation Commission

- UNS Electric, Inc. - Docket No. E-04204A-12-0504
- Tucson Electric Power Company - Docket No. E-01933A-12-0291
- Arizona Public Service Company - Docket No. E-01345A-11-0224

Before the Delaware Public Service Commission

- Delmarva Power and Light Company - Docket No. 12-546
- Delmarva Power and Light Company - Docket No. 11-528
- Delmarva Power and Light Company - Docket No. 07-239F
- Delmarva Power and Light Company - Docket No. 06-284

Before the Georgia Public Service Commission
- Georgia Power Company - Docket No. 36989

Before the Illinois Commerce Commission
- Commonwealth Edison - Case No. 05-0597

Before Maine Public Utilities Commission
- Northern Utilities Inc. - Case No. 2008-151
- Northern Utilities Inc. - Case No. 2004-813

Before the Maryland Public Service Commission
- Pepco and Delmarva Power and Light Company - Case No. 9092/9093

Before the Michigan Public Service Commission
- Consumers Energy Company - Case No. U-17688
- Detroit Edison Company - Case No. U-17689
- Detroit Edison Company - Case No. U-17097-R
- Consumers Energy Company - Case No. U-17095-R
- Detroit Edison Company - Case No. U-17319
- Consumers Energy Company - Case No. U-17496
- Consumers Energy Company - Case No. U-17429
- Detroit Edison Company - Case No. U-16892-R
- Detroit Edison Company - Case No. U-17097
- Detroit Edison Company - Case No. U-15768
- Detroit Edison Company - Case No. U-16656
- Consumers Energy Company - Case No. U-16655
- Detroit Edison Company - Case No. U-16434-R
- Detroit Edison Company - Case No. U-16047-R
- Detroit Edison Company - Case No. U-16434
- Detroit Edison Company - Case No. U-16892
- Detroit Edison Company - Case No. U-16472
- Michigan Consolidated Gas Company - Case No. U-16407
- Detroit Edison Company - Case No. U-16356
- Consumers Energy Company - Case No. U-16300
- Detroit Edison Company - Case No. U-16047
- Detroit Edison Co. and Michigan Consolidated Gas - Case No. U-15806/U-15890
- Consumers Energy Company - Case No. U-15805/15889
- Detroit Edison Company - Case No. U-15677-R
- Consumers Energy Company - Case No. U-15675-R
- Consumers Energy Company - Case No. U-15415-R
- Consumers Energy Company - Case No. U-15245
- Detroit Edison Company - Case No. U-15244
- Michigan Gas Utilities, Corporation - Case No. U-15040
- Consumers Energy Company - Case No. U-15001
- Consumers Energy Company - Case No. U-14701-R
- Consumer Energy Company - Case No. U-14547

Before the Missouri Public Service Commission
- Veolia Energy Company - Case No. HR-2011-0241

Before the Nebraska Public Service Commission
- Black Hills Energy/NE – Docket No. NG-0086

Before the New York Public Service Commission
- Long Island Lighting Company - Case No. 96-E-0132
- Niagara Mohawk Power Company - Case No. 96-M-0858
- Jamaica Water - Case No. 91-W-0583
- New York State Electric & Gas Homer City Prudence Review - Case No. 88-E-115

Before the North Dakota Public Service Commission
- Northern States Power Company - Case Nos. PU-10-657 and PU-11-55

Before the Nova Scotia Utility and Review Board
- Nova Scotia Power - Case No. P-888

Before the Utah Division of Public Utilities
- Rocky Mountain Power - Docket No. 09-035-23

Training and Public Speaking

Mr. McGarry has presented topics before Commission staff groups, NARUC sub-committee groups, and as a program faculty member (2010 & 2011) for the Institute of Public Utilities at Michigan State University. Topics presented include management auditing and prudence reviews, service company costs and allocations, forecasting methodology and modeling, revenue requirements, rate base, and price regulation theory, and cost trackers.

- National Association of Regulatory Utility Commissioners (NARUC). Presented, before the sub-committee on Accounting and Finance, a presentation on value of rate case audits. March 19, 2014
- NARUC. Presented, before the sub-committee on Accounting and Finance, a presentation on CAPEX trackers. March 28, 2012.
- Institute of Public Utilities, Michigan State University, East Lansing, MI. Presented a training session on Management Audits and Prudency Reviews to the attendees at the Institute of Public Utilities, Fall 2010 Advanced Regulatory Studies Program. September 27, 2011, and September 30, 2010.
- NARUC. Presented, before the sub-committee on Accounting and Finance, a presentation on service company costs and allocations to regulated entities. September 15, 2010.
- Special Case Study: Public Service Company of New Mexico, NM PRC Docket No. 10-00086-UT, June 2010. Worked with QSI Consulting, Inc. to conduct a training session for the New Mexico Public Service Commission Staff and to develop training materials for presentation to Staff on the basic elements of future test year

proceedings, how those may differ from traditional rate cases, and how to apply and interpret the forecasting methodologies and modeling that will come into play; and analyze the company's pending rate case and provide an analytic framework for Staff to apply to the forecasting issues in the case.

Professional Experience

Blue Ridge Consulting Services, Inc.: 2004-Present
President and CEO

Hawks, Giffels & Pullin, Inc.: 2003-2004
Vice President of East Coast Operations

Independent Consultant: 2001-2003

Denali Consulting, Inc.: 2000-2001
Senior Consultant

Navigant Consulting, Inc.: 1997-2000
Senior Consultant

New York State Department of Public Service: 1985-1997
Utility Operations Examiner

Seminole Electric Cooperative: 1983-1985
Rate Analyst II

Orange and Rockland Utilities: 1981-1983
Associate Rate Analyst

Education

Potsdam College, B.A., Economics, 1981
University at Buffalo School of Management, MBA, 1996

Schedule 2
TUCSON ELECTRIC POWER COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENT - STAFF ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2015

		Per Company Total Company		Per Staff Total Company		2008-2024 Per Company ACC Jurisdictional		2012-2015 Per Staff ACC Jurisdictional	
FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT	DEBIT	CREDIT	DEBIT	CREDIT	DEBIT	CREDIT
512	Maintenance of Boiler Plant - Four Corners	$2,700,063		$427,066		$2,582,841		$408,546	
512	Maintenance of Boiler Plant - Navajo		$1,140,984		$1,610,145		$1,091,449		$1,540,242
512	Maintenance of Boiler Plant - San Juan		$2,275,766		$858,500		$2,176,964		$819,316
512	Maintenance of Boiler Plant - Luna		$141,182		$480,787		$135,053		$459,914
512	Maintenance of Boiler Plant - Gila	$641,176		($174,592)		$613,340		($167,012)	
512	Maintenance of Boiler Plant - Springerville	$3,419,588		$2,853,168		$3,271,129		$2,729,299	
512	Maintenance of Boiler Plant - Sundt/Irvington	$1,582,059		$934,731		$1,513,375		$894,150	
512	Maintenance of Boiler Plant - ICT	$626,471		$0		$599,273		$0	
	ENTRY TOTAL	$8,969,357	$3,557,931	$4,040,394	$2,947,433	$8,579,958	$3,403,466	$3,884,983	$2,819,471
	NET ENTRY	$5,411,425		$1,092,962		$5,176,492		$1,045,512	
	Change			-$4,318,464		Change		-$4,130,980	-79.80%

Reason for Adjustment
To adjust the test year Overhaul expenses for major and minor overhauls at the Company's generationg stations.

Schedule 2
Tucson Electric Power Company
Overhaul Normalization Adjustment - Staff Adjustment
Test Year Ending June 30, 2015

Docket No. E-01933A-15-0322
Exhibit MJM-2 Schedule 2
page 2 of 2

Four Corners	Per Company		Per Staff		Actual Expenses 2012-2015 ($000's)[1] 2012	2013	2014	2015	Average
Estimated recurring expense	$ 2,700,063		$ 427,088		$ 280.0	$ -	$ 1,428.4	$ -	$ 427.1
Test year outage amount	$ -		$ -						
Adjustment	$ 2,700,063	A	$ 427,088						

Navajo	PER Company		Per Staff		Actual Expenses 2012-2015 ($000's) 2012	2013	2014	2015	Average
Estimated recurring expense	$ 1,384,559		$ 951,382		$ 1,244.0	$ -	$ -	$ 2,561.5	$ 951.4
Test year outage amount	$ 2,525,543		$ 2,561,527						
Adjustment	$ (1,140,984)	B	$ (1,610,145)						

San Juan	PER Company		Per Staff		Actual Expenses 2012-2015 ($000's) 2012	2013	2014	2015	Average
Estimated recurring expense	$ 2,188,235		$ 3,607,500		$ 8,000.0	$ -	$ 1,966.0	$ 4,464.0	$ 3,607.5
Test year outage amount	$ 4,464,000		$ 4,464,000						
Adjustment	$ (2,275,765)	C	$ (856,500)						

Luna	PER Company		Per Staff		Actual Expenses 2012-2015 ($000's) 2012	2013	2014	2015	Average
Estimated recurring expense	$ 944,201		$ 704,596		$ 1,633.0	$ -	$ -	$ 1,185.4	$ 704.6
Test year outage amount	$ 1,085,383		$ 1,185,383						
Adjustment	$ (141,182)	D	$ (480,787)						

Gila	PER Company		Per Staff		Actual Expenses 2012-2015 ($000's) 2012	2013	2014	2015	Average
Estimated recurring expense	$ 641,176		$ 58,197		$ -	$ -	$ -	$ 232.8	$ 58.2
Test year outage amount	$ -		$ 232,789						
Adjustment	$ 641,176	E	$ (174,592)						

Springerville	PER Company		Per Staff		Actual Expenses 2012-2015 ($000's) 2012	2013	2014	2015	Average
Estimated recurring expense	$ 3,419,588		$ 2,853,168		$ -	$ 3,595.7	$ 7,817.0	$ -	$ 2,853.2
Test year outage amount	$ -		$ -						
Adjustment	$ 3,419,588	F	$ 2,853,168						

Sundt/Irvington	PER Company		Per Staff		Actual Expenses 2012-2015 ($000's) 2012	2013	2014	2015	Average
Estimated recurring expense	$ 1,582,059		$ 934,731		$ -	$ 2,532.2	$ 1,206.7	$ -	$ 934.7
Test year outage amount	$ -		$ -						
Adjustment	$ 1,582,059	G	$ 934,731						

ICT	PER Company		Per Staff		Actual Expenses 2012-2015 ($000's) 2012	2013	2014	2015	Average
Estimated recurring expense	$ 626,471		$ -		$ -	$ -	$ -	$ -	$ -
Test year outage amount	$ -		$ -						
Adjustment	$ 626,471	H	$ -						

TOTAL	PER Company		Per Staff		Actual Expenses 2012-2015 ($000's) 2012	2013	2014	2015	Average
Net Estimated recurring expense	$ 13,486,351		$ 9,536,661		$ 11,157	$ 6,128	$ 12,418	$ 8,444	$ 9,536.7
Net Test year outage amount	$ 8,074,926		$ 8,443,699						
Net Adjustment	$ 5,411,425	Sum A	$ 1,092,962						

[1] - Source: UDR 1.001 - Workpaper titled: Income - Overhaul_Outage Normalization.xlsx, tab marked Outage Freq and Cost Worksheet ; Cols J - M by station

TUCSON ELECTRIC POWER COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2015

ADJUSTMENT NAME:	Overhaul & Outage Normalization
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	October 1, 2015
PREPARED BY:	Chip Bacon
CHECKED BY:	Steve Sims
REVIEWED BY:	

1A

		Total Company		ACC Jurisdictional	
FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT	DEBIT	CREDIT
512	Maintenance of Boiler Plant - Four Corners	$2,700,063		$2,582,841	
512	Maintenance of Boiler Plant - Navajo		$1,140,984		$1,091,449
512	Maintenance of Boiler Plant - San Juan		$2,275,765		$2,176,964
512	Maintenance of Boiler Plant - Luna		$141,182		$135,053
512	Maintenance of Boiler Plant - Gila	$841,176		$813,340	
512	Maintenance of Boiler Plant - Springerville	$3,419,588		$3,271,129	
512	Maintenance of Boiler Plant - Sundt/Irvington	$1,582,059		$1,513,375	
512	Maintenance of Boiler Plant - ICT	$626,471		$599,273	
	ENTRY TOTAL	$8,969,357	$3,557,931	$8,579,958	$3,403,466
	NET ENTRY	$5,411,425		$5,176,492	

Reason for Adjustment
To adjust the test year Overhaul expenses for major and minor overhauls at the Company's generationg stations.

Tucson Electric Power Company
Overhaul Normalization Adjustment
Test Year Ending June 30, 2016

Four Corners A

				Reference
Estimated recurring expense	$	2,700,063		1.1A
Test year outage amount	$	-		1.2A
Adjustment	$	2,700,063	A	Calculated

Navajo

				Reference
Estimated recurring expense	$	1,384,559		1.1B
Test year outage amount	$	2,525,543		1.2B
Adjustment	$	(1,140,984)	B	Calculated

San Juan

				Reference
Estimated recurring expense	$	2,188,235		1.1C
Test year outage amount	$	4,464,000		1.2C
Adjustment	$	(2,275,765)	C	Calculated

Luna

				Reference
Estimated recurring expense	$	944,201		1.1D
Test year outage amount	$	1,085,383		1.2D
Adjustment	$	(141,182)	D	Calculated

Gila

				Reference
Estimated recurring expense	$	641,176		1.1E
Test year outage amount	$	-		1.2E
Adjustment	$	641,176	E	Calculated

Springerville

				Reference
Estimated recurring expense	$	3,419,588		1.1F
Test year outage amount	$	-		1.2F
Adjustment	$	3,419,588	F	Calculated

Sundt/Irvington

				Reference
Estimated recurring expense	$	1,582,059		1.1G
Test year outage amount	$	-		1.2G
Adjustment	$	1,582,059	G	Calculated

ICT

				Reference
Estimated recurring expense	$	626,471		1.1H
Test year outage amount	$	-		1.2H
Adjustment	$	626,471	H	Calculated

Net Estimated recurring expense	$	13,486,351	
Net Test year outage amount	$	8,074,926	
Net Adjustment	$	5,411,425	*Sum A - H*

REFERENCE SHEET 1

1

Tucson Electric Power Company
Overhaul Normalization Adjustment
Test Year Ending June 30, 2015
normalized based on frequency of occurrence ($ 000's)

	<1>		<2>	<3> <1>/<2>		<4>		<5>	<6> <4>/<5>		<3>+<6>		
	Major overhauls					Minor overhauls					Major and Minor		
Plant	Average cost	Ref	frequency (Years)	Normalized costs		Average cost	Ref	frequency (years)	Normalized cost		Normalized Total		Ref
Four Corners unit 4	$ 4,321	1.2I	5.67	$ 763	Calc	$ 1,510	1.2AF	2.43	$ 622	Calc	$ 1,384	Calc	
Four Corners unit 5	$ 3,743	1.2J	4.25	$ 881	Calc	$ 1,232	1.2AG	2.83	$ 435	Calc	$ 1,316	Calc	
Total Four Corners	$ 8,065	Sum		$ 1,643	Sum	$ 2,742			$ 1,057	Sum	$ 2,700	Sum	A
Navajo unit 1	$ -	1.2K	17.00	$ -	Calc	$ 1,475	1.2AH	8.50	$ 174	Calc	$ 174	Calc	
Navajo unit 2	$ 2,588	1.2L	5.67	$ 457	Calc	$ 1,350	1.2AI	17.00	$ 79	Calc	$ 536	Calc	
Navajo unit 3	$ 2,500	1.2M	5.67	$ 441	Calc	$ 1,325	1.2AJ	5.67	$ 234	Calc	$ 675	Calc	
Total Navajo	$ 5,088	Sum		$ 898	Sum	$ 4,150			$ 487	Sum	$ 1,385	Sum	H
San Juan unit 1	$ 8,000	1.2N	5.67	$ 1,412	Calc	$ 4,400	1.2AK	5.67	$ 776	Calc	$ 2,188	Calc	
San Juan unit 2	$ -	1.2O	17.00	$ -	Calc	$ -	1.2AL	8.50	$ -	Calc	$ -	Calc	
Total San Juan	$ 8,000	Sum		$ 1,412	Sum	$ 4,400			$ 776	Sum	$ 2,188	Sum	C
Luna 1	$ 1,500	1.2P	8.50	$ 176	Calc	$ 1,491	1.2AM	4.25	$ 351	Calc	$ 527	Calc	
Luna 2	$ 1,500	1.2Q	17.00	$ 88	Calc	$ 1,397	1.2AN	4.25	$ 329	Calc	$ 417	Calc	
Total Luna	$ 3,000	Sum		$ 265	Sum	$ 2,888			$ 679	Sum	$ 944	Sum	D
Gila 3	$ 2,225	1.2R	8.50	$ 262	Calc	$ 2,150	1.2AO	5.67	$ 379	Calc	$ 641	Calc	
Total Gila	$ 2,225	Sum		$ 262	Sum	$ 2,150			$ 379	Sum	$ 641	Sum	B
Springerville unit 1	$ 3,429	1.2S	4.25	$ 807	Calc	$ 1,697	1.2AP	8.50	$ 200	Calc	$ 1,006	Calc	
Springerville unit 2	$ 7,590	1.2T	4.25	$ 1,786	Calc	$ 3,555	1.2AQ	5.67	$ 627	Calc	$ 2,413	Calc	
Total Springerville	$ 11,019	Sum		$ 2,593	Sum	$ 5,252			$ 827	Sum	$ 3,420	Sum	F
Irvington unit 1	$ 1,270	1.2U	5.67	$ 224	Calc	$ 883	1.2AR	4.25	$ 208	Calc	$ 432	Calc	
Irvington unit 2	$ 2,953	1.2V	4.25	$ 695	Calc	$ 900	1.2AS	5.67	$ 159	Calc	$ 854	Calc	
Irvington unit 3	$ 4,835	1.2W	8.50	$ 571	Calc	$ 1,663	1.2AT	4.25	$ 391	Calc	$ -	Calc	
Irvington unit 4	$ -	1.2X	17.00	$ -	Calc	$ 2,523	1.2AU	8.50	$ 297	Calc	$ 297	Calc	
Total Irvington	$ 9,058	Sum		$ 1,490	Sum	$ 5,968			$ 1,054	Sum	$ 1,583	Sum	G
DeMoss	$ -	1.2Y	-	$ -	Calc	$ -	1.2AV	17.00	$ -	Calc	$ -	Calc	
North Loop 1	$ 1,080	1.2Z	5.67	$ 191	Calc	$ -	1.2AW	-	$ -	Calc	$ 191	Calc	
North Loop 2	$ 1,170	1.2AA	17.00	$ 69	Calc	$ -	1.2AX	8.50	$ -	Calc	$ 69	Calc	
North Loop 3	$ -	1.2AB	8.50	$ -	Calc	$ 1,395	1.2AY	17.00	$ 82	Calc	$ 82	Calc	
North Loop 4	$ -	1.2AC	-	$ -	Calc	$ -	1.2AZ	-	$ -	Calc	$ -	Calc	
Sundt 1	$ 1,270	1.2AD	5.67	$ 224	Calc	$ -	1.2BA	-	$ -	Calc	$ 224	Calc	
Sundt 2	$ 1,035	1.2AE	17.00	$ 61	Calc	$ -	1.2BB	-	$ -	Calc	$ 61	Calc	
Total ICT	$ 2,250	Sum		$ 259	Sum	$ 1,395			$ 82	Sum	$ 626	Sum	H

REFERENCE SHEET 1.1

TEP(0322)003141

[Illegible] Electric Power Company
Distribution Normalization Adjustment
Test Year Ending June 30, 2015

Outage Type (Major or Minor)

Plant	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Four Corners unit 4	Minor		Minor	-	Minor	Major			Minor	Minor		Minor		Major	Major		Minor	Minor		Major
Four Corners unit 5	Minor	Minor	-	Major	Major	-	Minor	Major				Major	Major		Minor	Minor		Minor	Major	-
Navajo unit 1	Major			Minor			Major						Minor							
Navajo unit 2			Major			Major						Major			Minor			Major		
Navajo unit 3		Minor			Major			Major			Major			Major			Major			Minor
San Juan unit1		Major		Major			Minor				Major		Major		Major			Major		
San Juan unit 2	Minor		Minor		Major			Minor		Minor	Major									
Luna 1					Major			Minor			Major			Major			Major			Major
Luna 2			Minor				Minor						Major		Minor	Minor			Major	Major
Gila Unit 3													Major		Major	Major		Major	Major	
Springerville unit 1				Major		Major				Major					Major			Major		
Springerville unit 2	Major		Minor	Major		Major			Minor	Major		Major				Minor			Major	
Irvington unit 1	Minor			Minor		Major	Major			Minor		Major		Major				Major		
Irvington unit 2					Minor	Major	Major			Minor		Major				Major				Major
Irvington unit 3			Major	Major		Minor			Major			Major				Minor				Major
Irvington unit 4		Minor			Minor								Minor				Minor			
Dolan				Minor																
North Loop 1					Major	Major								Major						
North Loop 2					Minor	Minor										Major				
North Loop 3						Major	Major													Minor
North Loop 4																				
Saguaro 1									Major	Major								Major		
Saguaro 2												Major								

Frequency %		Frequency # of Years Between Outage	
Major	Minor	Major	Minor
11.8%	9.4%	8.47	2.45
8.2%	8.2%	4.25	2.43
6.7%	9.2%	17.00	8.50
9.1%	9.6%	8.67	17.00
9.1%	9.1%	8.67	8.67
9.1%	9.1%	8.67	8.67
6.7%	9.2%	17.00	8.50
9.1%	9.2%	8.50	4.25
6.7%	9.2%	17.00	4.25
9.1%	9.1%	8.50	3.89
6.2%	9.1%	4.25	8.50
9.2%	9.1%	4.25	3.67
9.1%	9.2%	3.67	4.25
9.2%	9.1%	4.25	3.67
9.2%	9.2%	8.50	4.25
6.7%	9.2%	17.00	8.50
-	0.0%	-	17.00
9.1%		8.67	
9.1%	9.1%	17.00	8.50
9.1%	9.1%	8.50	17.00
9.1%	9.1%	8.67	
9.1%		8.67	

Outage Cost ($ 000's)

Plant	Actual Cost										Budgeted Cost									
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Four Corners unit 4	132		212		218	1,010				1,138	-	2,227	-	3,906	615	-	5,166	845	-	4,855
Four Corners unit 5	291	211		1,019	295	-	1,012	261			-	1,542	1,651	-	817	2,051		977	4,016	
Total Four Corners											A	3,768	1,651	3,906	1,424	2,051	5,166	1,822	4,016	4,855
Navajo unit 1	1,999			1,211			3,124				-	-	1,471	-	-	-	-	-	-	
Navajo unit 2			352			1,311	-				2,975	-	-	1,190	-	-	-	2,870	-	
Navajo unit 3		516			3,597	-	-	1,211			2,152	-	1,755	-	-	-	3,500	-	-	1,315
Total Navajo											2,326 B	3,259	1,471	1,190	-	-	3,500	2,870	-	1,315
San Juan unit1	-	1,778	-	5,933	-	-	6,119	-	-	-	4,464	-	2,841	-	8,010	-	-	2,491	-	-
San Juan unit 2	1,708	-	1,202	-	4,138	-	-	8,042	-	1,974	-	-	-	-	-	-	-	-	-	-
Total San Juan											2,464 C	-	2,470	-	8,010	-	-	2,491	-	-
Luna unit 1					1,363	-	-	1,637			1,093	-	-	1,263	-	-	1,501	-	-	1,382
Luna unit 2				971			1,613				-	-	1,112	-	-	1,451	-	-	1,364	-
Total Luna											1,093 D	-	1,112	1,263	-	1,451	1,501	-	1,364	1,382
Gila Unit 3											-	-	2,250	-	2,830	1,301	-	2,108	1,350	-
Total Gila											E	-	2,250	-	2,830	1,301	-	2,108	1,350	-
Springerville unit 1				3,292	-	2,222			677	-	-	2,194	-	-	2,692	-	-	1,647	-	-
Springerville unit 2	3,068	-	2,991	3,933	-	2,479	-	-	7,188	7,813	-	-	2,466	-	-	1,650	-	-	2,592	-
Total Luna											- F	2,194	2,466	-	2,692	1,650	-	1,647	2,592	-
Ironwood unit 1	1,818	-	-	1,241	-	171	1,800	-	-	191	-	191	-	1,230	-	-	-	-	1,641	-
Ironwood unit 2	-	-	-	-	938	123	1,988	-	-	537	-	930	-	-	-	1,333	-	-	-	3,895
Ironwood unit 3	-	-	1,870	1,837	-	938	-	-	1,395	-	-	1,481	-	-	-	1,333	-	-	-	4,813
Ironwood unit 4	-	4,818	-	-	5,778	-	-	-	-	-	-	-	2,380	-	-	-	2,661	-	-	-
Total Ironwood											- G	2,602	2,380	1,230	-	2,667	2,661	1,641	-	8,708
Dolan				256	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Loop 1				-	644	631	-	-	-	-	-	-	-	1,888	-	-	-	-	-	-
North Loop 2				-	256	258	-	-	-	-	-	-	-	-	-	1,178	-	-	-	-
North Loop 3				-	-	987	615	-	-	-	-	-	-	-	-	-	-	-	-	1,295
North Loop 4				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Saguaro 1				-	-	-	-	-	767	459	-	-	-	-	-	-	-	1,295	-	-
Saguaro 2				-	-	-	-	-	-	-	-	1,015	-	-	-	-	-	-	-	-
Total SCT											- H	1,015	-	1,888	-	1,178	-	1,295	-	1,295

number of major scheduled	number of minor scheduled	Average Major $'s		Average Minor $'s		Annualized cost Major	Annualized cost Minor	Annualized cost Total
			Ref		Ref			
2	4	4,171.45	I	1,376	AF	792	612	1,404
3	1	2,741.46	J	1,241.72	AG	926	471	1,396
		3,065		2,912		1,643	1,017	2,760
1			K	1,475	AH		472	472
2	2	2,387.50	L	1,370	AI	451	79	530
3	2	2,902	M	1,313	AJ	441	231	672
		2,083		4,130		892	487	1,380
2	2	Worst	N	4,456	AK	1,817	576	2,394
		-	O	-	AL	-	-	-
		8,691		4,459		1,412	576	2,988
2	2	1,809	P	1,191.84	AM	196	331	527
1	1	1,909	Q	1,297.61	AN	96	121	217
		3,909		2,863		291	679	970
3	1	2,111	R	2,196	AO	262	379	641
		2,111		2,196		262	379	641
2	1	3,128.36	S	1,477	AP	892	259	1,151
1	3	2,991	T	2,335	AQ	1,700	627	2,327
		11,917		5,232		2,591	827	3,418
4	2	2,270	U	892.50	AR	322	205	527
2	1	2,953.26	V	980	AS	695	159	854
1	2	1,851	W	1,562.50	AT	672	391	963
2	2	-	X	2,220.75	AU	-	297	297
		9,075		5,768		1,689	1,057	2,746
			Y		AV			-
4	2	1,980	Z		AW	191		191
2		2,178	AA		AX	69	-	69
1		-	AB	1,375	AY	-	97	97
			AC		AZ			
		2,370	AD		BA	324		324
		2,032	AE		BB	81		81
		4,591		1,399		569	97	666
		40,847		26,794		8,615	4,465	13,080

REFERENCE SHEET 1.3

TEP(0322)003142

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SEVENTEENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 13, 2016

STF 17.07

Plant and Coal Handling Facilities closures: In February 2016 the US Supreme Court granted a stay to the implementation of the EPA's Clean Power Plan pending resolution of legal challenges to the program in court. Please explain in detail the impact of the "stay" on the Company's plans to close Power Plant units and also Coal Handling facilities. Please be specific regarding which Plants and units and also which rate base and Operating Income Pro-forma adjustments are impacted. If the stay does not impact rate case adjustments, please explain in detail why not.

RESPONSE:

At this point, the stay of the Clean Power Plan (CPP) and the likely delay in its implementation will have no immediate effect on near term plans to close Power Plant units or the related Coal Handling facilities. Per TEP's IRP, the Company continues to look for opportunities to reduce coal fired generation and replace it with a mix of natural gas fired generation and renewables. For example, in March 2016, TEP notified the EPA that as a result of Regional Haze Rule requirements it would stop burning coal at its Sundt Generating Station and switch permanently to natural and landfill gas. Additionally, at the San Juan Generating Station, TEP will along with the other San Juan Participants, shut Units 2 and 3 at the end of 2017 due to regional haze reduction requirements. TEP owns 50% of Unit 2. The early retirements of these facilities is addressed in the testimony of Mr. Marino and reflected in the depreciation study sponsored by Dr. White.

Longer term, depending on the ultimate CPP compliance timeframe and the requirements for carbon reduction in the final Court-approved rule, TEP will, as part of its resource diversification plan, determine what future closures may be appropriate. Accordingly, there are no pro-forma adjustments to rate base or operating income related to the CPP.

RESPONDENT:

Erik Bakken

WITNESS:

Frank Marino

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 18, 2016

STF 5.04

Service Quality - For each of the past four calendar years (2012-2015), please provide a listing of all service interruptions that had a duration of four (4) hours or more and affected more than 200 customers. Please include for each outage; the date and time, the ascribed cause, the duration of the outage, the number of consumers affected, the feeder or feeders affected, and the nature of the remedial efforts including equipment replaced, if any. Please include in this response a description of how the information in this response was obtained and recorded. The reference to "duration" means from the initial outage report from either the customer or system diagnostics to the restoration of service to the customer. If the vast majority (e.g., 90-95%) of the affected customers had service restored significantly sooner than the remaining customers affected by the outage, please describe the circumstances for each such episode.

RESPONSE: **March 9, 2016**

TEP is in the process of gathering this information and will provide it as soon as possible.

RESPONDENT:

Donovan Sandoval

WITNESS:

Susan Gray

SUPPLEMENTAL RESPONSE: **March 18, 2016**

TEP objects to the following portion of the request as the information is not readily available and would be unduly burdensome to gather such data: "If the vast majority (e.g., 90-95%) of the affected customers had service restored significantly sooner than the remaining customers affected by the outage, please describe the circumstances for each such episode." However, without waiver of objection, below is information obtained and recorded by the Company's Outage Management System regarding service interruptions, as requested.

File Name	Bates Numbers
STF 5.04 2012.pdf	TEP\021198-021199
STF 5.04 2013.pdf	TEP\021200
STF 5.04 2014.pdf	TEP\021201
STF 5.04 2015.pdf	TEP\021202

RESPONDENT:

Donovan Sandoval

WITNESS:

Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 9, 2016

STF 5.05

Service Quality - Please provide a list, including a description of the Company's response, of all complaints, formal or informal, made by customers to the Company, either directly or through the Arizona Corporation Commission, during each calendar year 2013 to the present that resulted from repetitive service outages and/or poor power quality, i.e., voltage levels, harmonics, "flicker," etc. Please include in this response details of all investigations performed by the Company and whether equipment modifications or equipment replacements resulted from the complaint and/or the investigations.

RESPONSE:

1. On June 20, 2013, a customer filed an ACC Complaint because her home was without power since noon that day. A TEP Representative left a detailed voicemail message for the customer on June 20, 2013 informing her about the service interruption. The majority of customers were back in power within 89 minutes. TEP replaced 5 poles/cross arms, a single phase transformer, a distribution switch and a distribution capacitor as a result of the semi-truck snagging conductors. The work completed was not a result of the complaint.
2. On July 10, 2013, a customer filed an ACC Complaint because his home was without power since the night before. A TEP Representative spoke to the customer on July 10, 2013 and provided information regarding the service interruption. TEP repaired 2 phases of conductor downed during a monsoon storm. The work completed was not a result of the complaint.
3. On September 17, 2013, a customer filed an ACC Complaint due to multiple service interruptions during the summer months. A TEP Representative spoke to the customer on September 18, 2013 and addressed his concerns. TEP was aware of the power interruptions due to monsoon damage (including poles/conductor down). No additional equipment modifications or replacements resulted.
4. On September 30, 2013, a customer filed an ACC Complaint due to a power outage at her apartment complex that day. A TEP Representative left a detailed voicemail message for the customer on October 5, 2013 informing her that a transformer had to be replaced due to a severe leak and the service was interrupted from 9:01am to 10:53am. The work completed was not a result of the complaint.
5. On December 3, 2015, a customer filed an ACC Complaint due to three power outages he experienced at his home within 7-10 days. A TEP Representative spoke to the customer on December 4, 2015 and addressed his concerns. TEP was aware of service interruptions caused by monsoon storms and failing/failed switching cabinets. These cabinets were replaced. The work completed was not a result of the complaint.

RESPONDENT:

Cara Roll

WITNESS:

Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 9, 2016

STF 5.06

Service Quality - Please describe and provide a copy of all studies performed by the Company since 2013 to assess the power quality of the system, including aspects of power factor.

RESPONSE:

TEP is in the process of gathering this information and will provide it as soon as possible.

RESPONDENT:

Donovan Sandoval

WITNESS:

Susan Gray

MICHAEL J. MCGARRY, SR.

SCHEDULE MJM-7

REDACTED

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S NINTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 28, 2016

STF 9.6

Maintenance Procedures – Provide a copy of the Company's transmission and distribution maintenance procedure manual(s).

RESPONSE:

The responsive files are too voluminous to provide in the data response. The information will be made available during Staff's site visit schedule to begin on Monday, March 28, 2016, and any time Staff would like to visit TEP's headquarters to review. If Staff would like to use any of the information in this matter, this response will be supplemented with the exact file(s), so that they are properly labeled and Bates stamped, as needed.

RESPONDENT:

Susan Gray / Ernie Ojeda / Tucson Legal Department

WITNESS:

Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S NINTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 28, 2016

STF 9.6

Maintenance Procedures – Provide a copy of the Company's transmission and distribution maintenance procedure manual(s).

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RESPONDENT:

Susan Gray / Ernie Ojeda / Tucson Legal Department

WITNESS:

Susan Gray

Critical Circuit Project
Criteria for Patrolling TEP Distribution Facilities

Overhead Facilities

Primary Conductor Inspection

1. Check for broken strands
2. Sag of conductors
3. Tree conditions in primary
4. Clearances from structures
5. Check for debris in the line

Pole Inspection

1. Inspect insulators (Flashed or damaged)
2. Inspect condition of cross arms. (This could include: broken, weathered, and wood pecker damage
3. Inspect condition of braces or related hardware
4. Inspect condition of tie wires
5. Inspect static assembly
6. Inspect security and condition of ground wire
7. Inspect any pole mounted equipment. (Transformers, capacitors, reclosure, cutouts and arrestors
8. Check for animals or debris on the ground near the pole
9. Inspect condition of switches, including verifying proper grounding on handles
10. Check overall condition of Pole, this would include: pole burst, knot rings, split or broken and shell rot
11. Inspect butt of pole and cored drill is signs of butt rot
12. Check leaning poles and determine reason, including butt rotted pole and anchor condition
13. Inspect condition of guy wire and integrity of guy rods
14. Check for excessive vegetation at base of poles and anchor rods
15. Check other utilities on pole that may endanger TEP's equipment (broken guys, lines hanging down)
16. Check connections with thermal gun or infrared tool

Underground Facilities

PMH, PME, Pullboxes, 3ph and 1ph Transformers and Junction Cabinet Inspection

1. Check overall condition of cabinet, including position on pad, corrosion, locks in place and stencils
2. Inspect terminations for discolor, swelling or flash damage
3. Check connections and terminations with thermal gun or infrared tool
4. Inspect over all condition for flash damage
5. Check for rodent damage
6. Check the neutral connection
7. Check vegetation for access restrictions and equipment labeling (refer to Vegetation Management to clear and install label if missing)

NOTE: Report any hazardous condition that can't be repaired by inspector, even if it's not on the critical circuit currently being patrolled.

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S NINTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 28, 2016

STF 9.6

Maintenance Procedures – Provide a copy of the Company's transmission and distribution maintenance procedure manual(s).

RESPONSE:

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RESPONDENT:

Susan Gray / Ernie Ojeda / Tucson Legal Department

WITNESS:

Susan Gray

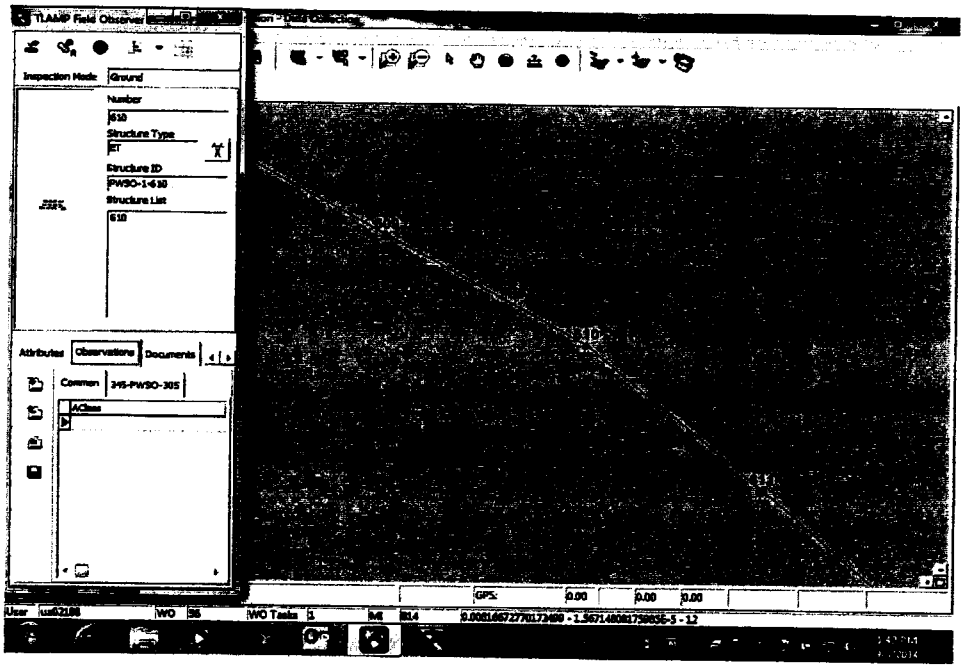
TEP Transmission Maintenance Inspection Process

The Transmission Maintenance Patrolman inspects all 46kV, 115kV, 138kV, and 230kV transmission structures at least once per year. In addition, the patrolman inspects a minimum of 1,000 structures along circuits that carry 345kV or more. This routine ensures that all 345kV and 500kV structures are inspected on a five-year cycle.

The patrolman records all inspections and maintenance tasks to a local database on a laptop using TLAMP Workman software (see screenshot below). At least once per month, he meets with the Transmission Maintenance Planner who backs up his database and syncs the new inspection and maintenance records with an enterprise database (see Figure 1). The planner estimates the cost of each identified maintenance task, prioritizes them by severity, and assigns them an ideal target date to complete the work. He then uses GIS to identify clustered areas where maintenance needs to occur and plans maintenance trips accordingly.

The Maintenance Planner periodically provides the patrolman with a report and a map (see Figure 2) depicting the structures he already inspected that year (green), the structures that were recently inspected (blue), and the structures that are awaiting inspection (red). The patrolman uses this as a guide for planning his work schedule for the remainder of the year.

The following are inspection checklists the patrolman follows when inspecting 345kV transmission lines on ground and climb patrols.



GROUND PATROL CHECKLIST
345-KV TRANSMISSION LINES

1. ACCESS

a. Map access on GPS mapping system-label road with tower # bracket (ie. A379-A390)
b. Note wash outs and other road conditions - inaccessible roads
c. Note gates, gate condition and lock status - repair inoperable or hard to use gates, if possible - interlock with 'B' lock if missing
d. Note encroachments on right of way such as structures, wells, other utilities, etc.
e. Note vegetation growing into or near midspan conductors including trees outside R/W which may fall into conductors. GPS location with description of tree variety, height, etc. If tree is dangerously close to conductor, report immediately

2. TOWER FOUNDATIONS AND ANCHORS/GUYS

a. Check concrete footings for degradation, surface spalling, cracks, exposed rebar, exposed aggregate, damage, settlement or displacement
b. Check anchors for erosion around grout and grout condition
c. Note soil material that is deposited over guys and/or anchor eyes
d. Check guy strand for damage
e. Check guying hardware for wear, corrosion, soundness at tower and anchor
f. Check preformed grips for damage or unraveling
g. Check guy rod for rusting or damage to shrink wrap
h. Check guys for tension, adjust u-bolts if required-record date of readjustment
i. Note vegetation growing into guys and/or tower steel - remove if possible - report findings
j. Do not report broken or missing ground leads

3. TOWER BODY

a. Check signs for legibility, condition, correct standard and soundness of fasteners - replace if required
b. Strike tower leg with hammer and listen for loose or rattling members
c. Check coating condition of members and note any corrosion or degradation of coatings
d. Check for missing members and/or fasteners
e. Report bird nests locations and if they are currently occupied. Report type of bird if possible. Note that nests are not to be removed unless eminent line outage may occur because of nest material and location.

High priority is to be place on reporting nests that have obvious metallic material in or hanging from nest.

4. CONDUCTOR/GUYING HARDWARE AND ATTACHEMENTS

a. Check guy attachments at tower attachment location for soundness and wear
b. Check conductor/shield wire shoes/AGS for loose hardware, backed out cotters keys or wear
c. Check that vibration dampers are present, secure and in good condition
d. Check insulator bells for broken or contaminated sheds, corrosion, burn marks, tracking or other damage - also check that cotter keys are securely in place. Note location of broken bells in string, number of bells damaged, amount if any of skirt remaining.
e. Check that insulated shield wire gap distance appears to be correct and all hardware is secure and in good condition
f. Check condition of fiber optic ground wire splice cans and leaders and that hardware is secure. Look for downlead securing points that are missing allowing lead to move. Note tower number of splice can location for cross checking
g. Check sub conductor spacers for wear or failure. Broken spacers are to be reported immediately
h. Check complete span of wire looking for damaged spacers or damage to the stranding on the conductor such as shot conductor. If core stranding is broken, report findings immediately

CLIMBING PATROL CHECKLIST
345-KV TRANSMISSION LINES

5. ACCESS

a. Map access on GPS mapping system
b. Note wash outs and other road conditions
c. Note gates, gate condition and lock status
d. Note encroachments on right of way
e. Note vegetation growing into or near midspan conductors

6. TOWER FOUNDATIONS AND ANCHORS/GUYS

a. Check concrete footings for degradation, surface spalling, cracks, exposed rebar, exposed aggregate, damage, settlement or displacement
b. Check anchors for erosion around grout and grout condition or deposit of material over guys and anchor eyes
c. Check guy strand for damage
d. Check guying hardware for wear, corrosion and soundness

e. Check preformed grips for damage or unraveling
f. Check guy rod for rusting or damage to shrink wrap
g. Check guys for tension, adjust u-bolts if required
h. Note vegetation growing into guys and/or tower steel - remove if possible - report findings
i. Record any damage or corrosion noted and guys needing re-tensioning

7. TOWER BODY

a. Check signs for legibility and soundness of fasteners - replace if required
b. Check all members while climbing for bends, loose fasteners or fatigue damage - repair as required
c. Check coating condition of members and note any corrosion or degradation of coatings
d. Check for missing members and/or fasteners
e. Report all repair/replacement describing location and type of repair including fastener tightening

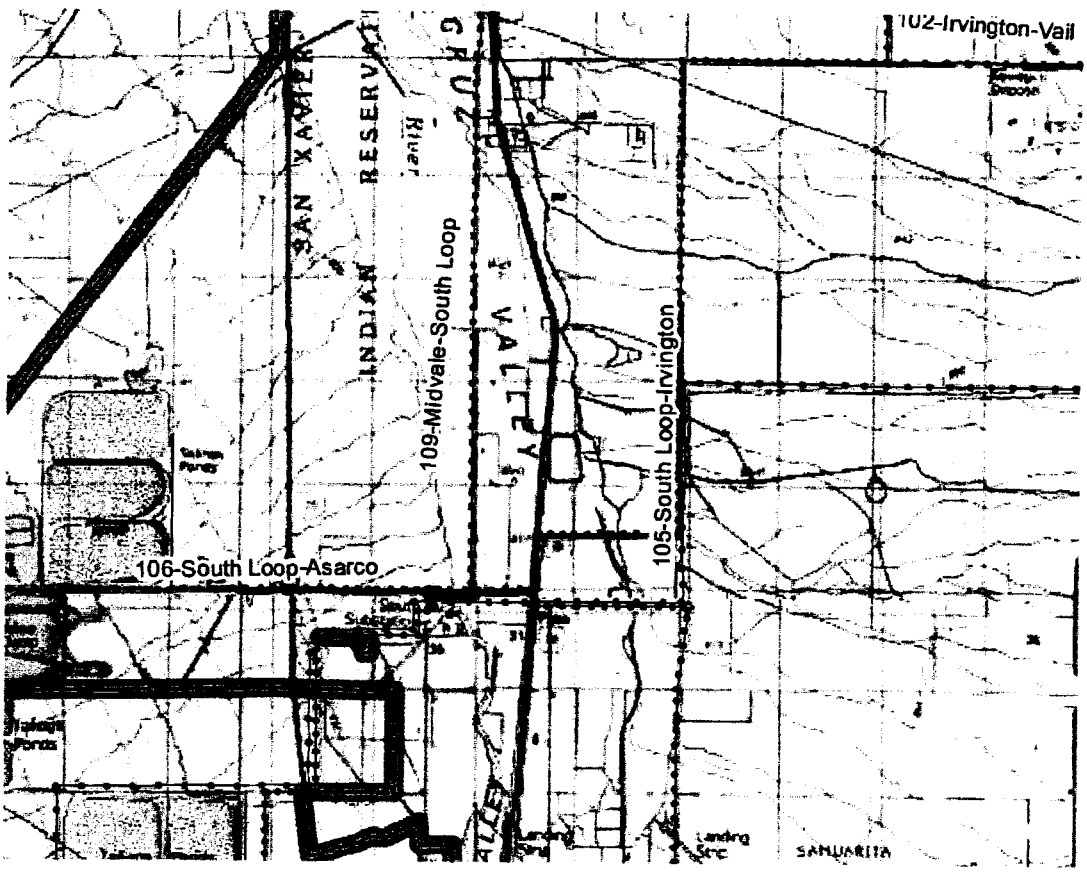
8. CONDUCTOR/GUYING HARDWARE AND ATTACHEMENTS

a. Check guy attachments at tower attachment location for soundness and wear
b. Check conductor/shield wire shoes/AGS for loose hardware, backed out cotters keys or wear
c. Check that vibration dampers are present, secure and in good condition
d. Check insulator bells for broken or contaminated sheds, corrosion, burn marks, tracking or other damage - also check that cotter keys are securely in place
e. Check gap distance is correct on insulated shield hardware and all hardware is secure and in good condition
f. Check condition of fiber optic ground wire splice cans and leaders and that hardware is secure
g. Report bird nests locations and if they are currently occupied. Report type of bird if possible. Do not remove nests unless eminent line outage may occur because of nest material and location.
h. Replace damaged or missing materials including pins, cotters, broken bells or fasteners
i. Check sub conductor spacers for wear or failure.
j. Report all observations, repairs and/or adjustments
k. Check ahead span of wire looking for damaged spacers or damage to the stranding on the conductor

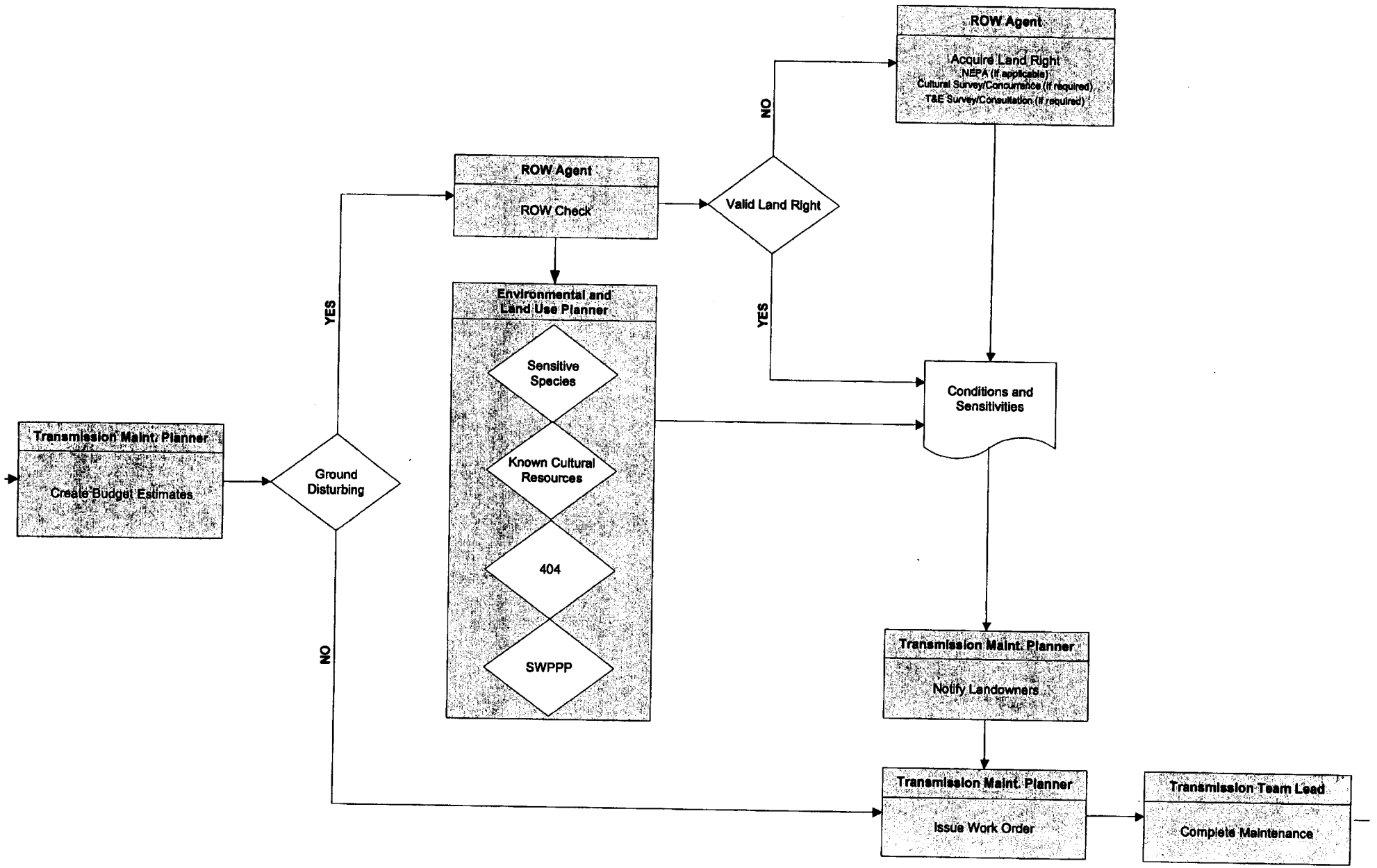
Figure 1: Database screenshot of inspected structures. The Maintenance Planner manages transmission work tasks in an enterprise database and a GIS

	A	B	C	D	E	F	G	H
1	Work_Order	Description	Location	Asset	Status	Work_Type	Report_Date	Actual_Finish
2	6055261	WORKMAN INSPECTION	22EL-1-174	8578	CLOSE	GRNDINSP	5/1/14	4/7/14
3	6055271	WORKMAN INSPECTION	22EL-1-164	8654	CLOSE	GRNDINSP	5/1/14	4/7/14
4	6055282	WORKMAN INSPECTION	22EL-1-135	8677	CLOSE	GRNDINSP	5/1/14	4/7/14
5	6055286	WORKMAN INSPECTION	22EL-1-140	8674	CLOSE	GRNDINSP	5/1/14	4/7/14
6	6055306	WORKMAN INSPECTION	22EL-1-118	8758	CLOSE	GRNDINSP	5/1/14	4/7/14
7	6055313	WORKMAN INSPECTION	22EL-1-116	8760	CLOSE	GRNDINSP	5/1/14	4/7/14
8	6055327	WORKMAN INSPECTION	WNVL-1-A563	5925	CLOSE	GRNDINSP	5/1/14	4/8/14
9	6051327	WORKMAN INSPECTION	VLRB-1-30N	5292	CLOSE	GRNDINSP	1/28/14	1/21/14
10	6051338	WORKMAN INSPECTION	VLRB-1-59	8203	CLOSE	GRNDINSP	1/28/14	1/21/14
11	6051343	WORKMAN INSPECTION	VLRB-1-31N	5291	CLOSE	GRNDINSP	1/28/14	1/21/14
12	6051387	WORKMAN INSPECTION	SLIR-1-12	8908	CLOSE	GRNDINSP	1/28/14	1/22/14
13	6051419	WORKMAN INSPECTION	SLIR-1-54	8702	CLOSE	GRNDINSP	1/28/14	1/22/14
14	6051433	WORKMAN INSPECTION	VLCG-1-72E	5372	CLOSE	GRNDINSP	1/28/14	1/23/14
15	6051445	WORKMAN INSPECTION	VLFT-1-76E	9306	CLOSE	GRNDINSP	1/28/14	1/23/14
16	6052622	WORKMAN INSPECTION	VLFT-1-141	9351	CLOSE	GRNDINSP	3/3/14	2/4/14
17	6052667	WORKMAN INSPECTION	SPVL-3-812	5701	CLOSE	GRNDINSP	3/3/14	2/11/14
18	6052673	WORKMAN INSPECTION	SPVL-3-813	5702	CLOSE	GRNDINSP	3/3/14	2/11/14
19	6052679	WORKMAN INSPECTION	WNVL-1-A524	6197	CLOSE	GRNDINSP	3/3/14	2/13/14
20	6052685	WORKMAN INSPECTION	SPVL-3-820	5751	CLOSE	GRNDINSP	3/3/14	2/13/14
21	6052691	WORKMAN INSPECTION	VLFT-1-162	9232	CLOSE	GRNDINSP	3/3/14	2/17/14
22	6052697	WORKMAN INSPECTION	VLFT-1-164	9230	CLOSE	GRNDINSP	3/3/14	2/17/14
23	6055331	WORKMAN INSPECTION	WNVL-1-A566	5928	CLOSE	GRNDINSP	5/1/14	4/8/14
24	6055681	WORKMAN INSPECTION	SJMC-1-N275	4335	SKIPCLOSE	GRNDINSP	5/1/14	4/25/14

Figure 2: Map depicting structures that are awaiting inspection (red), structures that were recently inspected (blue), and structures that were already inspected earlier in the year (green)



The following page shows an overview of the Transmission Maintenance process after the patrolman identifies maintenance tasks and syncs his local database of maintenance work orders and inspections with the enterprise database used by the planner.


ROW Agent
Acquire Land Right
NEPA (if applicable)
Cultural Survey/Concurrence (if required)
T&E Survey/Consultation (if required)
NO
ROW Agent
ROW Check
Valid Land Right
YES
Environmental and Land Use Planner
Sensitive Species
Known Cultural Resources
404
SWPPP
Conditions and Sensitivities
YES
Transmission Maint. Planner
Create Budget Estimates
Ground Disturbing
NO
Transmission Maint. Planner
Notify Landowners
Transmission Maint. Planner
Issue Work Order
Transmission Team Lead
Complete Maintenance

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 9, 2016

STF 5.01

SAFETY - Regarding Witness Gray's testimony at page 3, line 25 to page 4 line2, please provide the materials/documentation provided to Company employees and/or its customers that support the Company's "Target Zero" safety strategy. Please also provide the documentation that shows the elements of the Target Zero strategy.

RESPONSE:

The essential safety policy of the company can be summed up as follows: No operating condition or urgency of service can ever justify endangering the life of anyone. This is evidenced by the Company's Target Zero safety strategy that provides the framework for safety processes and programs.

The following narrative showing the elements of the Target Zero strategy is taken directly from the foreword of the Tucson Electric Power Co. / IBEW 1116 Joint Safety Committee Safety Manual:

> *Target Zero is nothing more -- and nothing less -- than a personal commitment by every person in the organization to "Work in a manner that prevents injury". To work in a manner that prevents injury, every individual evaluates each job or decision and verifies that the actions being taken will support the prevention of injury to themselves, their co-workers, the public and those who will follow in their footsteps. We can all work in a manner that prevents injury by using the following elements:*
>
> *1. Job Design*
>
> *2. Planning*
>
> *3. Communication*
>
> *4. Mutual Support/Teamwork*
>
> *5. Task Management*
>
> *6. Situational Awareness*
>
> *7. Decision Making*
>
> *8. Debriefing*
>
> *The safety of every person working for Tucson Electric Power Co. and of the public, is an integral part of who we are. Let's provide and use the tools, equipment, conditions, knowledge and time necessary to work in a manner that prevents injury.*

The aforementioned eight essential elements of working in a manner that prevents injury support the Target Zero Strategy and are well established in company culture, programs and documentation. Additionally, this strategy provides the structure for Company safety leadership training branded as Leading in a Manner That Prevents Injury ("LTPI"). LTPI Training supporting

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Target Zero was introduced in 2009, with a revision built on case studies in 2013, and a strategic rebranding and implementation planned for 2016.

Training Support Materials referenced:

File Name	Bates Numbers
STF 5.01 LTPI 1.0 (2009-2012).pdf	TEP\019984-020179
STF 5.01 LTPI 2.0 (2013-2015) Facilitators Guide.pdf	TEP\020180-020198
STF 5.01 LTPI 3.0 (2016 -) Prototype.pdf	TEP\020199-020262

RESPONDENT:

Brian Herman

WITNESS:

Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 9, 2016

STF 5.03

SAFETY - Regarding Witness Gray's testimony at page 4, table/box at lines 10-12, please provide the detailed back-up for this data by year and by the Company's Distribution Services Area Map (see https://www.tep.com/doc/tep-area-map.pdf).

a. Please update the table for calendar year 2015.

b. Please fully explain the causes for the increases in the TRIR between 2012 and 2013 - .80 to .96 and 2013 to 2014 - .96 to 1.67.

c. Please fully explain the difference between 2014 and calendar year 2015. Include any new programs that the Company may have implemented to affect this change.

RESPONSE:

ONE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

File Name	Bates Numbers
STF 5.03 TEP OSHA Form 300 2012.pdf	TEP\020366-020368
STF 5.03 TEP OSHA Form 300 2013.pdf	TEP\020369-020372
STF 5.03 TEP OSHA Form 300 2014.pdf	TEP\020373-020375
STF 5.03 TEP OSHA Form 300 2015.pdf	TEP\020376-020377
STF 5.03 T&D 2015 Goals-Confidential.xlsx	N/A
STF 5.03 2015 Ops Safety Summit Final Group Presentation.pdf	TEP\020263-020365

a.

	2012	2013	2014	2015
T&D Operations TRIR	0.80	0.96	1.67	0.4

b. In 2012, TEP had 3 recordable injuries resulting in the TRIR of .80 which were:

1) New Service Representative: Strained wrist from keyboard work.

2) Journeyman Lineman: Lacerated toe from dropped drill with bit.

3) Pre-Apprentice: Stung on neck by insect in vehicle.

Supporting Material Included: **STF 5.03 TEP OSHA Form 300 2012.pdf.**

In 2013, TEP had 5 recordable injuries resulting in the TRIR of .96 which were

1) Journeyman Lineman: Lacerated hand with knife while removing fencing wire.

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2) Crew Leader: Lacerated hand from material slipping and pinning hand between tailgate while loading.

3) Intern: Lacerated hand from drill.

4) Equipment Operator: Bitten by spider, caused infection.

5) Serviceman: Bruised foot from dropping plate

Supporting Material Included: **STF 5.03 TEP OSHA Form 300 2013.pdf.**

In explaining the increase from 2012 to 2013, there are a few factors that should be discussed. None of the incidents involved a serious injury or fatality or had the potential to cause serious injury or fatality. Most of the injuries were minor in nature and resulted from interactions with the work environment. Two of the injuries involved insect stings and bites. None of the injuries involved violations of published safety rules.

In 2014, TEP had 8 recordable injuries resulting in the TRIR of 1.67 which were:

1) Journeyman Lineman: Laceration of finger from a hand tool.

2) Journeyman Lineman: Strained back from shoveling debris around a transformer.

3) Journeyman Lineman: Pinched finger while loading a cabinet into a truck.

4) Apprentice Lineman: Lacerated finger from hand tool.

5) Apprentice Lineman: Strained knee from stepping in a trench.

6) Journeyman Lineman: Strained ankle from stepping off truck onto uneven ground.

7) Journeyman Substation Electrician: Injured toes from dropping a plate.

8) Equipment Serviceman: lacerated hand from power tool.

Supporting Material Included: **STF 5.03 TEP OSHA Form 300 2014.pdf.**

Regarding the increase from 2013 to 2014, there are additional factors to consider. Two of the incidents involved employees simply losing their footing at jobsites. Four of the incidents involved hand injuries that were specifically addressed with introducing cut-resistant Kevlar gloves and cable strippers to be used in lieu of knives while stripping cable. Pinch point safety and hand safety were discussed in a monthly safety meeting.

In 2015, TEP had 2 recordable injuries resulting in the TRIR of .40 which were:

1) Journeyman Metering Tech: Strained shoulder from pulling cable.

2) Automotive Tech: Contusion of thumb from hammer.

Supporting Material Included: STF 5.03 TEP OSHA Form 300 2015.pdf.

c. Targeted initiatives were implemented in calendar year 2015 in response to the opportunities identified from the 2014 calendar year. The annual Safety Summit was facilitated in January 2015 to benchmark best practices across the industry, discuss 2014

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incidents, identify trends, and to develop specific goals related to incident prevention: Supporting Material Included: STF 5.03 2015 Ops Safety Summit Final Group Presentation.pdf.

Each operating unit developed a detailed goal to affect safety performance change in the following categories: Leadership, Employee Engagement, and Regulatory Compliance / Hazard Control.

The initiatives developed by TEP Transmission & Distribution consisted of:

Leadership: Improved leadership engagement in the safety process with employees in the field. Increased the frequency of employee field & shop visits from 1 to 2 per employee, per year. Increased leadership field & shop visits to at least 3 per quarter for superintendents & directors, 6 per quarter for supervisors, 12 per for group & team leads.

Employee Involvement: Increased the level of T&D operations representation and proactive participation in the Joint Safety Committee as a problem solving action-oriented entity.

Regulatory Compliance/Hazard Control: Develop policies & procedures to ensure compliance with 1910.269 revisions regarding minimum approach distances & arc flash analysis.

Supporting Material Included: **STF 5.03 T&D 2015 Goals-Confidential.xlsx.**

RESPONDENT:

Brian Herman

WITNESS:

Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
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STF 5.02

SAFETY - Regarding Witness Gray's testimony at page 4, lines 22-24, please provide the management reports and related backup documentation which supports Witness Gray's statement that "focused implementation of this strategy throughout the Company has resulted in an excellent and sustained total recordable incident rate from 2012 through June of 2015."

RESPONSE:

The Target Zero strategy and the supporting programs are the primary drivers of safety performance improvement in the organization.

Based on comparison to the industry average and benchmarking against other electric transmission, control and distribution utilities, TEP has sustained excellent safety performance over the period from 2012 to 2015. Throughout the period in question, TEP has demonstrated consistent safety performance that delivers TRIR below the industry average in every year.

Total Recordable Incident Rates from 2012 to 2015 are provided in STF 5.03(a).

Industry Average: **2.8** (Based on U.S. Bureau of Labor Statistics Most Current Data Re: Electric Power Transmission, Control & Distribution - NAICS code 22112) Ref: http://www.bls.gov/iif/oshwc/osh/os/ostb4343.pdf

RESPONDENT:

Brian Herman

WITNESS:

Susan Gray

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 07, 2016

STF 6.01

Plant Additions:

Please provide the following information for the plant addition abbreviated as CBOAD00 San Juan Repl and Bett.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

r. Provide supporting information for any salvage values including the ultimate disposition

of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE: **March 18, 2016**

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx". The Excel file is not identified by Bates numbers.

b./c. TEP is in the process of gathering this information and will provide it as soon as possible.

d. This project consists of several distinct construction efforts which have independent completion dates. Please see Table 2 in file "STF 6.01 - 6.25 Project Details.xlsx".

e./f. TEP is in the process of gathering this information and will provide it as soon as possible.

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx"

h.-p TEP is in the process of gathering this information and will provide it as soon as possible.

p. There have been none.

q. There are two types of methods in which assets can be transferred from construction work in process ("CWIP") to Plant in Service ("PIS") – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. The retirement and cost of removal associated with this project occurred as a result of replacement or obsolescence during construction of new assets. Please see table 3 in file "STF 6.01 - 6.25 Project Details.xlsx".

t./u. TEP is in the process of gathering this information and will provide it as soon as possible.

RESPONDENT:

Diane Grant (a, d, g, q-s) and John Baum (b, c, e, f, h-p, t, u)

WITNESS:

Frank Marino and David Hutchens

SUPPLEMENTAL RESPONSE: **April 07, 2016**

In response to data request STF 10.11, the file STF 6.01 - 6.25 Project Details.xlsx has been revised. Please see STF 6.01 – 6.25 Project Details–Revised 04-04-16.xlsx. The Excel file is not identified by Bates numbers. This change applies to all responses in Staff's 10th set of data requests.

RESPONDENT:

Jason Rademacher

WITNESS:

Frank Marino

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 18, 2016

STF 6.02

Plant Additions:

Please provide the following information for the plant addition abbreviated as CBOND96 Dist System Integrity.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

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r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE:

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx"

b. This project supports multiple distribution and sub-transmission (46kV) maintenance line work orders. The following are types of capital replacement line work:

- Priority 3 capital replacement line work
- Annual System Ordered Circuit Patrol, SOCP
- Annual Recloser Capital Replacement Program
- Special Projects - Priority 3 capital replacement line work identified by TEP engineering.

c. The project was budgeted and the approval was part of the annual capital budget approval process.

d. This project consists of several distinct construction efforts which have independent completion dates. Please see Table 2 in file "STF 6.01 - 6.25 Project Details.xlsx".

e. None.

f. This project was estimated at $6,742,000. Year-end variances due to reprioritization of construction resources.

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx"

h. Combination of Company employees and contractors. No safety incidents or concerns recorded due to this project.

1. Some work orders are completed by contract crews under the Company's 3-year alliance bid agreement for work orders under $250k in labor. No bid analysis is required for alliance contractor work under $250k in labor.
2. TEP supplied inspectors for oversight of contractor work to provide access and ensure quality of work.
3. No capital work was deferred to allow this project to be completed.

i. Not applicable.

j. There were no delays.

k. Yes, as-built drawings have been completed

l. Not applicable. TEP purchased equipment is tested by the manufacturer prior to shipment.

m. Yes, TEP purchased equipment is warrantied by the manufacturer.

n. Yes, other procedures exist that monitor and patrol routine maintenance needed on capital distribution line assets.

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o. No, the extra maintenance is absorbed in our annual O&M budget.

p. No outages related to the project since the in-service date.

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. The retirement and cost of removal associated with this project occurred as a result of replacement or obsolescence during construction of new assets. Please see table 3 in file "STF 6.01 - 6.25 Project Details.xlsx".

t. No, all capital replacement line work is distribution and sub-transmission (46kV). All capital equipment within this budget is replaced like for like or replaced to meet new TEP standard requirements.

u. No claims were filed with any insurers for this project.

RESPONDENT:

Dominic Carter (a, d, g, q-s) and Cynthia Garcia (b, c, e, f, g-p, t, u)

WITNESS:

Frank Marino and Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 18, 2016

STF 6.03

Plant Additions:

Please provide the following information for the plant addition abbreviated as CBONI00 Meters & Metering Equipment.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

   1. Fully explain the variance in project costs from 2013 to 2014, $3.4M to $10.7M.

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

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r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE:

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

b. By 2013, Tucson Electric Power had deployed approximately 50% of the meters in the field as Electronic Radio Transmitter ("ERT") meters capable of being read by the Automatic Meter Reading ("AMR") network. In order to better utilize that investment and to gain efficiencies in meter reading, the meter exchanges were accelerated in order to get a 100% penetration rate. This completely deployed ERT equipped meters and fully utilized the fixed network. This implementation also provides additional capabilities and rate design flexibility by obtaining interval meter information for each customer.

c. The project was approved as part of the 2014-2015 Capital Budget. The approval was part of the annual capital budgeting cycle.

d. This project consists of several distinct construction efforts which have independent completion dates. Please see Table 2 in file "STF 6.01 - 6.25 Project Details.xlsx".

e. See STF 6.03(e) AMR Implementation Analysis.pdf, Bates Nos. TEP\021277-021287, for the NPV computations. It shows a base case, or a 7 year implementation, and the resulting NPV and IRR for reducing the implementation duration in increments of one year, all the way to what we ultimately were approved for, which was a 3 year implementation.

f. The 2013 budget of $3.4M was based on exchanging 20,000-30,000 meters per year. The decision to expedite the meter exchanges was made in 2013, so the 2014 budget was increased to $10.7M to accommodate the accelerated exchange rate. This increased cost included 15 additional SES temporary employees and additional material (meters).

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

h. The project was constructed by TEP staff and SES. SES hired temporary employees to handle the meter exchanges. Some additional temporary administrative staff was hired by TEP to handle the sharp increase in paperwork.

1. TEP received outside bids to perform the installation of meters that went through the Company's competitive bidding process. TEP is unable to provide the actual bids without approval of the contractor due to the competitively sensitive confidential nature of the bidding process.

2. SES is a subsidiary of UNS, SES performs metering work on behalf of TEP as part of TEP's metering processes. To execute the meter exchanges, an enlarged staff was trained and monitored by the SES leadership. By utilizing SES, TEP maintained more direct control over the flow and pace of the project to prevent creating undue strains on Customer Service and Billing. It also presented a

beneficial customer experience utilizing a company that was already familiar to customers and allowed TEP to control customer contacts and questions.

3. The majority of the exchanges were performed by the additional staff at SES. The TEP metering group performed some additional exchanges by working overtime. No planned capital/O&M work was deferred.

i. There was no off site work performed.

j. There were no delays.

k. There are no as built drawings as these are meter exchanges. The CIS system was updated with the new meter information as part of the exchange process.

l. All meters are tested at the factory before shipping. The vendor emails the test results for each shipment of meters to TEP metering personnel. The results are uploaded into the TEP CIS system for archiving. To validate the manufacture testing, the manufacturer randomly selects 10% of each order shipment and places them on a separate pallet. This pallet of meters was tested by TEP when they were received to verify the meters met the testing requirements. The meters are tested using an RFL 5800 test set.

m. The project consisted of purchases of the same meters we were purchasing before the project. The meters have a warranty associated with workmanship of three years.

n. The meters will be exchanged within 15 years eliminating any maintenance requirements.

o. Subsequent budgets reflect changes in expense based on the installation of new assets, including reductions in meter reading expenses, and increases in equipment and software amortization expense and other software-related maintenance costs.

p. There have been none.

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. No retirement or cost of removal are recorded for this project.

t. No notifications were required as this was not a transmission project.

u. Claims were within our self-insured retention below our excess insurance coverage. We booked the self-insured expense as it was incurred.

RESPONDENT:

Dominic Carter (a, d, g, q-s) and Ernesto Ojeda (b, c, e, f, h-p, t, u)

WITNESS:

Frank Marino and Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
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STF 6.04

Plant Additions:

Please provide the following information for the plant addition abbreviated as CBOSK04 SGS U2 Turbine/Circ Water.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE:

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

b. This construction effort was to:

1. Replace the original generator rotor that was at the end of its normal operating life with a new, current design rotor.
2. Replace the turbine main steam stop and control valves.
3. Replace leaking and deteriorated cooling tower distribution valves and deteriorated cooling tower circulating water screens.

c. Yes, project was included in approved capital budget.

d. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

e. This task was justified for reasons of reliability and ability to serve rather than payback on investment.

f. Cost estimates were included in the capital approval documentation.

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

h. 1. The equipment was sole-sourced to the original equipment manufacturer ("OEM") and TEP sole-sourced justification procedures were followed. TEP received outside bids to perform the installation work, which went through the Company's competitive bidding process. TEP is unable to provide the actual bids without approval of the contractor due to the competitively sensitive confidential nature of the bidding process.

2. A contractor performed the generator work. Company engineers or maintenance supervisors provided contractor oversight.

A combination of contractors and company employees was used to accomplish the turbine valve work. Company engineers or maintenance supervisors provided contractor oversight.

3. Capital/expense work was not deferred to perform this project. When used, plant personnel and their time was budgeted for the project.

i. 1. Rotor was manufactured off-site and installed on-site.

2. Valves were manufactured off-site and installed on-site.

3. Valves and screens were manufactured off-site and installed onsite.

j. No delays due to parts availability, labor availability, weather, design constraints, permitting or unanticipated problems.

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k. As-built drawings completed as required.

l. The generator rotor was subjected to over-speed and electrical tests off-site. Also subjected to a battery of electrical tests on-site before being placed into service.

Turbine valves were subjected to in-field testing of sealing surfaces and calibration.

Cooling tower valves and screens were not tested prior to being placed in service.

m. All equipment warrantied by manufacturer.

n. Maintenance procedures have been scheduled within appropriate maintenance system.

o. No

p. None

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. The retirement and cost of removal associated with this project occurred as a result of replacement or obsolescence during construction of new assets. Please see table 3 in file "STF 6.01 - 6.25 Project Details.xlsx".

t. No FERC approval required

u. No Insurance Claims

RESPONDENT:

Wanda Nerney (a, d, g, q-s) and Pat Fahey (b, c, e, f, h-p, t, u)

WITNESS:

Frank Marino and David Hutchens

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
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STF 6.05

Plant Additions:

Please provide the following information for the plant addition abbreviated as CBOSK01 SGS U2 Blanket.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE:

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx"

b. This construction effort:

1. Replaced a number of critical valves, pumps, and motors associated with the boiler feedwater system that were worn out or performing poorly.
2. Upgraded or replaced the distributed controls system and the turbine programmable logic controller because they were obsolete and at end-of-life with diminishing support from the original equipment manufacturers.
3. Replaced plant instrumentation that had failed like analyzers, positioners, and transmitters or upgraded lighting to improve visibility and safety.
4. Overhauled/replaced a primary air fan.

c. Yes, project was included in approved capital budget. Various tasks included in this project.

d. This project consists of several distinct construction efforts which have independent completion dates. Please see Table 2 in file "STF 6.01 - 6.25 Project Details.xlsx".

e. These tasks were justified for reasons of reliability and ability to serve rather than payback on investment.

f. Cost estimates were included in the capital approval documentation.

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx"

h. 1. Both sole-source and competitive bid processes were performed for this project TEP is unable to provide the actual bids without approval of the contractor due to the competitively sensitive confidential nature of the bidding process.

2. A combination of contractors and company employees was used to accomplish this work. Company engineers or maintenance supervisors provided contractor oversight.

3. Capital/expense work was not deferred to perform this project. When used, plant personnel and their time was budgeted for the project.

i. Components, i.e., valves, motors, pumps, servers, controllers, actuators, etc. were fabricated or overhauled, assembled, and tested off-site and then installed on-site.

j. No delays due to parts availability, labor availability, weather, design constraints, permitting or unanticipated problems.

k. As-built drawings completed as required.

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l. New and rebuilt pumps, motors, components, etc. tested at factory according to specifications.

Equipment and/or components tested at factory according to specifications.

m. All equipment warrantied by manufacturer.

n. Preventive maintenance (PM) and Predictive Maintenance (PDM) schedules were established per the manufacturer's recommendations.

Maintenance procedures have been scheduled within appropriate maintenance system.

o. Where applicable, yes.

p. None

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. The retirement and cost of removal associated with this project occurred as a result of replacement or obsolescence during construction of new assets. Please see table 3 in file "STF 6.01 - 6.25 Project Details.xlsx".

t. No FERC approval required.

u. No Insurance Claims

RESPONDENT:

Wanda Nerney (a, d, g, q-s) and Pat Fahey (b, c, e, f, h-p, t, u)

WITNESS:

Frank Marino and David Hutchens

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
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STF 6.06

Plant Additions:

Please provide the following information for the plant addition abbreviated as CBOSH02 SGS U12 Coal Yard.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

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r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?.

RESPONSE:

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx"

b. This construction effort included:

1. Replacing service water piping, vacuum piping, and washdown sump pumps to improve housekeeping and safety in the coalyard.

2. Upgrading or replacing equipment to preserve the reliability and operability of the coal conveying system.

3. Purchasing portable conveyors.

c. Yes, project was included in approved capital budget. Various tasks included in this project. Capital approval documents can be made available.

d. This project consists of several distinct construction efforts which have independent completion dates. Please see Table 2 in file "STF 6.01 - 6.25 Project Details.xlsx".

e. These tasks were justified for reasons of reliability and ability to serve rather than payback on investment.

f. Cost estimates were included in the capital approval documentation.

g. "STF 6.01 - 6.25 Project Details.xlsx"

h. 1. Both sole-source and competitive bid processes were performed for this project TEP is unable to provide the actual bids without approval of the contractor due to the competitively sensitive confidential nature of the bidding process.

2. A combination of contractors and company employees was used to accomplish this work. Company engineers or maintenance supervisors provided contractor oversight.

N/A. Purchase of new portable equipment.

3. Capital/expense work was not deferred to perform this project. When used, plant personnel and their time was budgeted for the project.

i. Components, i.e., piping, valves, pumps, were manufactured off-site and then fully installed on-site

Materials, i.e., plate steel, electrical wire, were manufactured off-site and then fully installed on-site.

Portable conveyors were manufactured off-site.

j. No delays due to parts availability, labor availability, weather, design constraints, permitting or unanticipated problems.

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k. As-built drawings completed as required.

l. Field tested when placed into service.

m. All equipment warrantied by manufacturer.

n. Maintenance procedures have been scheduled within appropriate maintenance system.

o. Where applicable, yes

p. None

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. The retirement and cost of removal associated with this project occurred as a result of replacement or obsolescence during construction of new assets. Please see table 3 in file "STF 6.01 - 6.25 Project Details.xlsx".

t. No FERC approval required.

u. No Insurance Claims

RESPONDENT:

Wanda Nerney (a, d, g, q-s) and Pat Fahey (b, c, e, f, h-p, t, u)

WITNESS:

Frank Marino and David Hutchens

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
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March 21, 2016

STF 6.07

Plant Additions:

Please provide the following information for the plant addition abbreviated as D12PD41 SGS 10MW Expansion.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

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r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?.

RESPONSE: **March 18, 2016**

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

b. It is consistent with the company's philosophy to meet the RES compliance by using both Power Purchase agreements and self-owned Renewable Generating assets.

c. Yes. Typically, the amount of capital budget requested for a project(s) is equal to the amount that the ACC approves TEP to spend including, ancillary costs, as requested in the company's Implementation Plan. This amount is included in TEP's overall capital budget. TEP's Board of Directors provides final approval for the Capital budget.

d. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

e. Engineering studies were done to confirm that the proposed site would not negatively impact the local grid. TEP's value analysis is based on meeting the RES requirement as economically as possible.

f. TEP is in the process of gathering this information and will provide it as soon as possible.

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

h. The Renewable Project and the interconnection were constructed by 3rd party contractors.

Safety – No safety incidents

1. Both procurement and construction of the project was selected using a competitive RFP process based on qualifications, value, experience and price.

2. Renewable site:

The major components of the renewable site, the SunPower C7 concentrating single axis tracker with related components, the T5 silicon modules and inverters including the electrical design for those components were procured directly from SunPower Corp by TEP. The remainder of the design, balance of system components and site construction were contracted to Gehrlicher Solar America Corp.

TEP had weekly phone meetings with all parties which included discussions on:

- Integration of the differing engineering disciplines into a final design
- Integration of TEP standards into the design
- Construction updates
- Scheduling
- QA/QC
- Budget

- Project close out

TEP had a bi-weekly (or greater) presence on the jobsite to review progress

Interconnection

TEP's 3rd party contractors were under the immediate and constant supervision of a TEP construction manager.

1. No capital/expense work was deferred for this project

i. ABB inverter stations were constructed off site by the manufacturer and delivered to the site for installation. These stations include inverters, transformers, monitoring equipment, and supporting AC/DC switchgear.

The required interconnection breaker for this facility was constructed off site by the manufacturer and delivered to the site for installation.

j. The original C.O.D. for the project was 4th quarter 2013. Due to a lengthy, but unsuccessful, land negotiation with Tohono O'odham Nation the project was relocated to TEP's Springerville Generating Station. This caused delays due to redesign, reshipping and renegotiation of contract terms and pricing. The revised C.O.D. was 4th quarter 2014. There were no other noteworthy delays. There was no disruption to AFUDC as that process was not started until the site location was confirmed and moved to the Springerville site.

k. Yes

l. SMA, ABB, and Advanced Energy Field Service Technicians along with contractor and Company employees tested and commissioned each inverter on site prior to energizing and back feeding power to the Springerville distribution system.

SunPower Field Technicians along with contractor tested and commissioned the C7 single-axis tracker system.

Contractor completed I-V curve trace analysis for the system. Facility production analysis was also performed by the contractor to confirm the facility was operating as designed.

m. Yes, all product was delivered and installed with warranties in place.

n. Vegetation management for the site was completed in Q1, 2016.

Contractor is completing the annual system testing & inspections for the C7 single-axis tracker system in Q1, 2016

Contractor is scheduled to complete annual system testing & inspections for the T5 fixed-tilt system in Q2, 2016.

In addition, Company employees conduct quarterly site inspections as part of the ongoing operations & maintenance of this facility

o. Yes, costs for operations & maintenance of this facility are accounted for in budgets approved as part of the REST plan.

p. One day site outage on February 3rd 2015 to support a maintenance outage associated with the adjacent SGSSS facility.

One day site outage on December 9th 2015 to inspect the ABB transformers

Six day site outage starting on May 20th 2015 due to a connection failure at the interconnection breaker.

One day site outage on February 16th 2016 to replace ABB transformer.

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. No retirement or cost of removal are recorded for this project.

t. Transmission upgrades were not required to support the interconnection of this facility. This facility interconnects to the Company's 34.5kV distribution system and followed the Distributed Generation Interconnection Requirements, therefore FERC notification was not required.

u. No insurance claims filed.

RESPONDENT:

Wanda Nerney (a, d, g, q-s), Jeff Krauss (b, c, e, f, h, j, k, m, u) and Gabe Torres, Chris Lindsey, (i, l, n-p, t)

WITNESS:

Frank Marino / Carmine Tilghman

SUPPLEMENTAL RESPONSE: March 21, 2016

f. This estimate was based off of a 2010 solar module supply RFP and subsequent award to SunPower Corp for 11.3 MWdc of T5 modules delivered and paid for from Q3 2011 through 2013. The project estimate was $4 per watt dc broken out as $3/W for material and $1/W for construction costs or $45,200,000.00.

In 2012 an amendment to the contract was executed such that 7.02MWdc of the T5 were to be replaced by an equal amount of the C7 product.

RESPONDENT:

Jeff Krauss (f)

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
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STF 6.08

Plant Additions:

Please provide the following information for the plant addition abbreviated as D07BL04 Pwest-Srosa Line & Sub Partcptn.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

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r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?.

RESPONSE:

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

b. From a state-wide perspective, the Project provides a necessary component of the transmission infrastructure by providing service for the load growth the state was experiencing at the time of the planning for the project. It accomplishes this by providing an additional path to move energy from new generation facilities near the Palo Verde hub to the load areas, as well as alleviate transmission constraints. This project enabled the movement of energy from the Palo Verde area, an energy market hub, to southern Arizona. Specifically for TEP it provided Pinal Central as a point to which TEP could construct a 500kV line providing TEP direct connectivity between its service territory and the Palo Verde hub which is a major source of energy for TEP.

c. The project was budgeted and the approval was part of the annual capital budget approval process.

d. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

e. From a regional perspective, this Project is a segment of a larger transmission plan identified through the Central Arizona Transmission System (CATS) Study. The CATS Study was prepared collaboratively by eighteen public and private utility companies with the participation of the Arizona Corporation Commission (ACC). The purpose of the Study was to examine ways to increase transmission capacity throughout the state, specifically in central Arizona. The CATS study identified this project as a component to address the regional need for electrical transmission infrastructure. Load growth throughout the state of Arizona was taxing the existing transmission facilities. The existing electrical system was developed in a time when transmission lines were associated with specific generating projects. It was not envisioned to be a robust system providing unencumbered access to the "electric grid." This Project was developed to address the increased demand for energy delivery in central Arizona improving transmission capacity, reliability, and overall system support. The proposed Project also provided additional transmission capacity to support future growth in Maricopa, Pinal, and Pima Counties and provides increased reliability to the central Arizona power grid, as a whole, in accordance with the CATS study objective.

f. The total project cost was estimated by SRP and any changes were managed by SRP.

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g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

h. SRP was the project manager for the project and hired a line contractor to construct the project. TEP personnel were not directly involved in the construction of the project or oversight of any contractors.

i. The line and substations were constructed on site.

j. Construction on the project progressed in accordance with the schedule determined by the project manager.

k. SRP is the operating agent for the line and was responsible for obtaining and maintaining the as-built drawings.

l. Yes the line was tested in accordance with SRP procedures. SRP was responsible for all the testing and commissioning of equipment before it was placed in-service.

m. SRP was responsible for equipment purchases and did obtain appropriate warranties.

n. SRP is responsible for maintenance procedures.

o. Yes, as SRP has identified future O&M costs they get incorporated into TEP's budget.

p. No outages related to the project since the in-service date.

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. No retirement or cost of removal are recorded for this project.

t. The participation agreement amongst the parties was provided to FERC. TEP did not request specific approval of the project for itself. This is not required by FERC.

u. TEP did not file any claims with any of our insurers for this segment of the overall project.

RESPONDENT:

Randy Deming (a, d, g, q-s) and Ana Bustamante (b, c, e, f, h-p, t, u)

WITNESS:

Frank Marino and Susan Gray

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
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STF 6.09

Plant Additions:

Please provide the following information for the plant addition abbreviated as D14PD43 2014 Bright Buildout Plan Fort Huachuca.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?.

RESPONSE: **March 18, 2016**

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

b. The Fort Huachuca PV Project was built as a collaboration between the Company, Fort Huachuca, and the Department of Defense to meet both Company renewable requirements as well as meet the Army's goal of deploying 1 Gigawatt of renewable energy resources.

c. Yes. Typically, the amount of capital budget requested for a project(s) is equal to the amount that the ACC approves TEP to spend, including ancillary costs, as requested in the company's Implementation Plan. This amount is included in TEP's overall capital budget. TEP's Board of Directors provides final approval for the Capital budget.

d. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

e. Engineering studies were done to confirm that the proposed site would not negatively impact the local grid. TEP's value analysis is based on meeting the RES requirement as economically as possible.

f. TEP is in the process of gathering this information and will provide it as soon as possible.

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx"

h. The Renewable Project was constructed by a 3rd party EPC. The interconnection for the project was constructed by TEP employees.

Safety - Yes, a contractor entered an energized section of Inverter 8A during system commissioning. Work was stopped to re-establish the proper clearance procedure to complete the work safely.

1. After a competitive solicitation where-in TEP requested cost + 5% contract terms, E-on SE was the only firm willing to except the terms.

2. Renewable site:

   E-on SE was responsible for Engineering, Procurement and Construction with guidance from TEP as noted below.

   TEP had weekly phone meetings with all parties which included discussions on:

   - Integration of the differing engineering disciplines into a final design
   - Integration of TEP standards into the design
   - Construction updates
   - Scheduling
   - QA/QC
   - Budget

- Project close out

TEP had a weekly (or greater) presence on the jobsite to review progress

i. SMA inverters, GE Prolec pad-mount transformers, and S&C switchgear were assembled by these manufacturers off site and installed as part of the overall project by both contractors and Company employees.

j. The scheduled COD date was Q4 2014. The COD date was met without notable delays.

k. Yes

l. SMA Field Service Technicians along with contractor and Company employees tested and commissioned each inverter on site prior to energizing and back feeding power to the Fort Huachuca Substation.

Contractor completed I-V curve trace analysis for the system. Facility production analysis was also performed by the contractor to confirm the facility was operating as designed.

m. Yes, all product was delivered and installed with warranties in place.

n. Contractor completed site inspection for the facility in Q1, 2015

Vegetation management for the site was completed in Q1, 2016.

Contractor completed the annual system testing & inspections for the facility in Q1, 2016

In addition, Company employees conduct monthly site inspections as part of the ongoing operations & maintenance of this facility

o. Yes, costs for operations & maintenance of this facility are accounted for in budgets approved as part of the REST plan.

p. Eight day site outage starting on January 8th 2015 due to required work at the Fort Huachuca Substation.

One day site outage on December 15th 2015 to inspect GE Prolec transformers

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. No retirement or cost of removal are recorded for this project.

t. Transmission upgrades were not required to support the interconnection of this facility. This facility interconnects to the Company's 13.8kV distribution system and followed the Distributed Generation Interconnection Requirements, therefore FERC notification was not required.

u. No insurance claims filed

RESPONDENT:

Wanda Nerney (a, d, g, q-s), Jeff Krauss (b, c, e, f, h, j, k, m, u) and Gabe Torres, Chris Lindsey, (i, l, n-p, t)

WITNESS:

Frank Marino / Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
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f. The land for the site was provided to TEP in an easement from Fort Huachuca as part of the agreement referenced in section b. Procurement and construction costs were estimated to be $1.75/watt or $30,100,000.00.

RESPONDENT:

Jeff Krauss (f)

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
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STF 6.10

Plant Additions:

Please provide the following information for the plant addition abbreviated as D13SK07 SGS U2 LP1 and LP2.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE:

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

b. This construction effort was to replace the low pressure (LP) turbine full inner module including: new LP inner casing, fully bladed rotors, fully bladed carriers, hardware, and specialty tooling.

c. Yes, project was included in approved capital budget.

d. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

e. This project was justified for reasons of reliability and economic payback.

f. Cost estimates were included in the capital approval documentation.

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

h. 1. Material was sole-sourced to the OEM and TEP sole-sourced justification procedures were followed. TEP received outside bids to perform the installation work, which went through the Company's competitive bidding process. TEP is unable to provide the actual bids without approval of the contractor due to the competitively sensitive confidential nature of the bidding process.and TEP sole-sourced justification procedures were followed. TEP received outside bids to perform the installation work, which went through the Company's competitive bidding process. TEP is unable to provide the actual bids without approval of the contractor due to the competitively sensitive confidential nature of the bidding process.

2. Contractors performed this work. Company engineers or maintenance supervisors provided contractor oversight.

3. N/A

i. Equipment was manufactured off-site and installed on-site.

j. No delays due to parts availability, labor availability, weather, design constraints, permitting or unanticipated problems.

k. As-built drawings completed as required.

l. Rotor over-speed testing performed at OEM site.

m. All equipment warrantied by manufacturer.

n. Maintenance procedures have been scheduled within appropriate maintenance system.

o. No

p. None

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q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. The retirement and cost of removal associated with this project occurred as a result of replacement or obsolescence during construction of new assets. Please see table 3 in file "STF 6.01 - 6.25 Project Details.xlsx".

t. No

u. No Insurance Claims

RESPONDENT:

Wanda Nerney (a, d, g, q-s) and Pat Fahey (b, c, e, f, h-p, t, u)

WITNESS:

Frank Marino and David Hutchens

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STF 6.11

Plant Additions:

Please provide the following information for the plant addition abbreviated as D05BL01 Palo Verde-Pinal West Part.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

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r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE:

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

b./c. TEP is in the process of gathering this information and will provide it as soon as possible.

d. This project consists of several distinct construction efforts which have independent completion dates. Please see Table 2 in file "STF 6.01 - 6.25 Project Details.xlsx".

e./f. TEP is in the process of gathering this information and will provide it as soon as possible.

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

h.-p. TEP is in the process of gathering this information and will provide it as soon as possible.

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. The retirement and cost of removal associated with this project occurred as a result of replacement or obsolescence during construction of new assets. Please see table 3 in file "STF 6.01 - 6.25 Project Details.xlsx".

t./u. TEP is in the process of gathering this information and will provide it as soon as possible.

RESPONDENT:

Randy Deming (a, d, g, q-s) and Ana Bustamante (b, c, e, f, h-p, t, u)

WITNESS:

Frank Marino and Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
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STF 6.12

Plant Additions:

Please provide the following information for the plant addition abbreviated as D08BP01 Vail T3 345/138kV Xfmr Add.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

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r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE:

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

b. This project was constructed to provide capacity for load served from Vail. The 345kV expansion required the relocation of the Vail-South Loop line by extending the bus and adding four (4) 345kV breakers, and eight (8) 345kV switches. One 672 MVA 345kV/138kV transformer was installed in the bay 4 position.

An additional fifth 345kV breaker and ninth 345kV switch was installed to tie the express line to the "B" bus for contingency switching.

c. The project was budgeted and the approval was part of the annual capital budget approval process.

d. This project consists of several distinct construction efforts which have independent completion dates. Please see Table 2 in file "STF 6.01 - 6.25 Project Details.xlsx".

e. The purpose of the project is to comply with NERC Planning Standards and WECC System Performance Criteria.

f. The project was estimated at $19.5M. Miscellaneous adjustments were made during the project.

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

h. The project was constructed by a combination of company employees and contractors. There was one incident that occurred during construction where a line was inadvertently tripped when the wrong cable was cut. No customer outage, just a tripped line for a brief period of time.

1. The civil and physical construction request for quotation was sent to 6 companies. The 4 bids received were compared on price, accuracy and ability to adhere to the schedule.
2. TEP supplied inspectors for oversight of contractor work to provide access and ensure quality of work.
3. No capital work was deferred to allow this project to be completed.

i. The transformer, switches, and breakers were built by the manufacturer at their sites then installed and tested at Vail Substation.

j. There were no delays.

k. As-built drawings have been completed.

l. Substation Engineering provided standard testing procedures and the procedures were followed prior to commissioning the equipment.

m. The transformer and breakers were purchased with a warranty from the manufacturer.

n. Yes, the required maintenance procedures have been established as described below:

- Doble (set of diagnostic tests that prove integrity of the transformer) and sudden pressure relay testing after 1 year, 3 years, 5 years and every 3rd year thereafter.
- Monthly warranty inspection for first five years.
- Annual infrared inspections.
- Annual Dissolved Gas Analysis ("DGA") tests.
- Inspection every 4 months during the major sub inspection.
- Annual and more detailed 3 year GCB inspections.

o. No, the extra maintenance is absorbed in our annual O&M budget.

p. There was one outage. The transformer was gassing so the manufacturer was brought in for repairs.

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. The retirement and cost of removal associated with this project occurred as a result of replacement or obsolescence during construction of new assets. Please see table 3 in file "STF 6.01 - 6.25 Project Details.xlsx".

t. TEP did not notify FERC or seek approval for the referenced projects. FERC does not require pre-approval of projects.

u. We did not file any claims with any of our insurers for this project.

RESPONDENT:

Randy Deming (a, d, g, q-s) and Ana Bustamante (b, c, e, f, h-p, t, u)

WITNESS:

Frank Marino and Susan Gray

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STF 6.13

Plant Additions:

Please provide the following information for the plant addition abbreviated as D12PD38 Prairie Fire.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

r. Provide supporting information for any salvage values including the ultimate disposition

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of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE: **March 18, 2016**

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

b. It is consistent with the company's philosophy to meet the RES compliance by using both Power Purchase agreements and self-owned Renewable Generating assets.

c. Yes. Typically, the amount of capital budget requested for a project(s) is equal to the amount that the ACC approves TEP to spend, including ancillary costs, as requested in the company's Implementation Plan. This amount is included in TEP's overall capital budget. TEP's Board of Directors provides final approval for the Capital budget.

d. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

e. Engineering studies were done to confirm that the proposed site would not negatively impact the local grid. TEP's value analysis is based on meeting the RES requirement as economically as possible.

f. TEP is in the process of gathering this information and will provide it as soon as possible.

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx"

h. The Renewable Project was constructed by a 3rd party EPC. The interconnection for the project was constructed by TEP employees.

Safety – No safety incidents

1. TEP received outside bids to perform the installation of this project that went through the Company's competitive bidding process. TEP is unable to provide the actual bids without approval of the contractor due to the competitively sensitive confidential nature of the bidding process.

2. Renewable site:

Solon Corporation was responsible for Engineering, Procurement and Construction with guidance from TEP as noted below.

TEP had weekly phone meetings with all parties which included discussions on:

- Integration of the differing engineering disciplines into a final design
- Integration of TEP standards into the design
- Construction updates
- Scheduling
- QA/QC
- Budget
- Project close out

TEP had a weekly (or greater) presence on the jobsite to review progress

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3. No Capital/expense work was deferred for this project.

i. Advanced Energy inverters, pad-mount transformers, and G&W switchgear were assembled by these manufacturers off site and installed as part of the overall project by both contractors and Company employees.

j. The scheduled COD date was Q4 2012. The COD date was met without notable delays.

k. Yes

l. Advanced Energy Field Service Technicians along with contractor and Company employees tested and commissioned each inverter on site prior to energizing and back feeding power to the grid.

Contractor completed I-V curve trace analysis for the system. Facility production analysis was also performed by the contractor to confirm the facility was operating as designed.

m. Yes, all product was delivered and installed with warranties in place.

n. Contractor completed the annual system testing & inspection for the facility in Q2, 2014.

Contractor completed the annual system testing & inspection for the facility in Q3, 2015

Vegetation management for the site was completed once in 2014, twice in 2015, and once in 2016.

In addition, Company employees conduct monthly site inspections as part of the ongoing operations & maintenance of this facility

o. Yes, costs for operations & maintenance of this facility are accounted for in Company O&M budgets approved annually.

p. One day outage on October 7th, 2014 for maintenance purposes.

One day outage on July 29th 2015 for maintenance purposes.

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. No retirement or cost of removal are recorded for this project.

t. Transmission upgrades were not required to support the interconnection of this facility. This facility interconnects to the Company's 13.8kV distribution system and followed the Distributed Generation Interconnection Requirements, therefore FERC notification was not required.

u. No insurance claims filed.

RESPONDENT:

Wanda Nerney (a, d, g, q-s), Jeff Krauss (b, c, e, f, h, j, k, m, u) and Gabe Torres, Chris Lindsey, (i, l, n-p, t)

WITNESS:

Frank Marino / Carmine Tilghman

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SUPPLEMENTAL RESPONSE: March 21, 2016

f. The project estimate was $4 per watt dc broken out as $3/W for material and $1/W for construction costs or $20,000,000.00.

RESPONDENT:

Jeff Krauss (f)

WITNESS:

Carmine Tilghman

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STF 6.14

Plant Additions:

Please provide the following information for the plant addition abbreviated as D12AC67 Concentrated Solar.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

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r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE:

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

b. TEP partnered with Areva Solar to develop a concentrated solar booster augmentation project that could integrate solar thermal technology with an existing power plant facility. The Areva technology offered advantages over other Concentrated Solar Power (CSP) technologies including footprint, cost, and operating temperature range. The Areva Solar technology also utilized water as the working fluid instead of oils or molten salts typically found with other CSP technologies. The project for the H. W. Sundt Facility was designed as a low-cost CSP facility that could be scaled up to larger capacities to support other exiting power plant facilities.

c. The solar steam generator ("SSG") was approved through the REST program.

d. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

e. Engineering studies were done to confirm that the proposed site would not negatively impact the local grid. TEP's value analysis is based on meeting the RES requirement as economically as possible.

f. See attached cost estimate: STF 6.14(f) TEP Solar Proj Future Cost 083115.pdf, Bates Nos. TEP\021288-021288.

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

h. There was a safety incident on October 28, 2014 where non-destructive testing (Gamma/X-ray) was performed on a pipe weld without the knowledge of TEP personnel. See attached incident report: Pipe XRAY AREVA.DOCX.

1. TEP received outside bids to perform the installation of this project that went through the Company's competitive bidding process. TEP is unable to provide the actual bids without approval of the contractor due to the competitively sensitive confidential nature of the bidding process.
2. Oversight was contracted for construction of the solar tie-in portion of the project.
3. TEP employee involvement was minimized as to not defer any work.

i. The mirror assembly, receiver and structure was constructed offsite by Caid Industries and assembled on site.

j. No delays. While Areva could not begin construction because of financial constraints in the Fall 2011, TEP continued with the removal of old oil storage tanks and site grading.

k. Drawings and records have been completed.

l. A comprehensive performance acceptance test, meeting ASME requirements was agreed to by TEP and Areva. These tests were performed per the plan and the Areva system met the performance expectations.

m. All equipment purchased are accompanied by a manufacturer warranty.

n. All maintenance activities are scheduled through our maintenance system. Please see STF 6.14 SSG PMs.xlsx. The Excel file is not identified by Bates numbers.

o. Yes, the additional O&M work requirements were absorbed into the plant budgets.

p. Often times, work is performed during cloudy days when the facility cannot be operated reducing the need for an outage. However, Areva elected to bring the facility down in January through March 2016 to repair mirrors and temperature elements prior to the turnover to TEP.

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. No retirement or cost of removal are recorded for this project.

t. No.

u. No.

RESPONDENT:

Wanda Nerney (a, d, g, q-s) and Conrad Spencer (b, c, e, f, h-p, t, u)

WITNESS:

Frank Marino and David Hutchens

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STF 6.15

Plant Additions:

Please provide the following information for the plant addition abbreviated as D14SK02 02 Boiler Outage Work.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

r. Provide supporting information for any salvage values including the ultimate disposition

of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE:

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

b. This construction effort during a planned overhaul/outage was for boiler tube replacements to improve unit reliability and reduce forced outages due to tube leaks.

c. Yes, project was included in approved capital budget.

d. This project consists of several distinct construction efforts which have independent completion dates. Please see Table 2 in file "STF 6.01 - 6.25 Project Details.xlsx".

e. This project was justified for reasons of reliability.

f. Cost estimates were included in the capital approval documentation.

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

h. 1. TEP received outside bids to perform the work, which went through the Company's competitive bidding process. TEP is unable to provide the actual bids without approval of the contractor due to the competitively sensitive confidential nature of the bidding process.

2. Contractors performed this work. Company engineers or maintenance supervisors provided contractor oversight.

3. None.

i. Material was manufactured off-site and installed on-site.

j. No delays due to parts availability, labor availability, weather, design constraints, permitting or unanticipated problems.

k. As-built drawings completed as required

l. Dye penetrant testing performed on tube welds. Hydrostatic testing performed to identify tube leaks prior to placing unit in service.

m. All equipment warrantied by manufacturer.

n. Maintenance procedures have been scheduled within appropriate maintenance system.

o. No

p. None

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. The retirement and cost of removal associated with this project occurred as a result of replacement or obsolescence during construction of new assets. Please see table 3 in file "STF 6.01 - 6.25 Project Details.xlsx".

t. No

u. No insurance claims.

RESPONDENT:

Wanda Nerney (a, d, g, q-s) and Conrad Spencer (b, c, e, f, h-p, t, u)

WITNESS:

Frank Marino and David Hutchens

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STF 6.16

Plant Additions:

Please provide the following information for the plant addition abbreviated as D13HC03 Ft Huachuca 138kV Xfmr Rplc.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

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r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE:

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

b. The transformer failed requiring replacement under emergency conditions.

c. No – the transformer failed before a budget was approved.

d. This project consists of several distinct construction efforts which have independent completion dates. Please see Table 2 in file "STF 6.01 - 6.25 Project Details.xlsx".

e. This transformer serves a customer (Ft. Huachuca) off a radial line.

f. None

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

h. Work was completed by both TEP and contractors. Company employees constructed the physical and electrical portions and the contractor provided the civil construction. There was one incident that occurred during energizing where a termination failed in the cabinet of the switchgear causing damage to the cubicle. There was no customer outage, but repairs needed to be made.

1. The civil work was sole-sourced and TEP sole-sourced justification procedures were followed.
2. TEP supplied inspectors for oversight of contractor work to provide access and ensure quality of work.
3. Resources were allocated to this job as a result of failure of original transformer. Capital work schedules were adjusted accordingly.

i. The switchgear building and the control shelter were both constructed off-site by the manufacturer. All portions of the civil and physical construction were constructed on site.

j. There were some minor delays due to design & parts availability constraints because the job was a response to a transformer failure. There were also minor weather delays, and the failed termination but no measureable delays were experienced.

k. As-built drawings have been completed.

l. Substation Engineering provided standard testing procedures and the procedures were followed prior to commissioning the equipment.

m. The transformer, breakers, and switchgear were purchased with a warranty from the manufacturer.

n. The following maintenance procedures have been established:

1. Doble (Set of diagnostic tests that prove integrity of the transformer) and sudden pressure relay testing after 1yr, 3yrs, 5yrs and every 3rd thereafter.

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2. Monthly warranty inspection for first five years.
3. Annual infrared inspections.
4. Annual Dissolved Gas Analysis (DGA) tests.
5. Inspection every 4 months during the major sub inspection.
6. Quarterly battery inspection/maintenance.
7. 3 year GCB inspections.

o. No, the extra maintenance is absorbed in our annual O&M budget.

p. No outages related to the project since the in-service date

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. The retirement and cost of removal associated with this project occurred as a result of replacement or obsolescence during construction of new assets. Please see table 3 in file "STF 6.01 - 6.25 Project Details.xlsx".

t. TEP did not notify FERC or seek approval for the referenced projects. FERC does not require pre-approval of projects.

u. We did not file any claims with any of our insurers for this project.

RESPONDENT:

Randy Deming (a, d, g, q-s) and Ana Bustamante (b, c, e, f, h-p, t, u)

WITNESS:

Frank Marino and Susan Gray

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STF 6.17

Plant Additions:

Please provide the following information for the plant addition abbreviated as D09IQ02 Duval Cir 138kV Sub.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

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r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE:

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

b. Transmission Planning and Distribution Planning determined that the underlying 46kV system would not have adequate transformer capacity to support the load growth in the Green Valley area for loss of the South-Green Valley 138kV circuit beyond the 2013 to 2016 time frame. Extending the 138kV to FMI-Sierrita (Canoa Ranch-Duval Clear 138kV project) allows for continuity of service for loss of a 138kV circuit in Green Valley.

c. The project was budgeted and the approval was part of the annual capital budget approval process.

d. This project consists of several distinct construction efforts which have independent completion dates. Please see Table 2 in file "STF 6.01 - 6.25 Project Details.xlsx".

e. Transmission Planning and Distribution Planning determined the underlying 46kV system would not have adequate transformer capacity to support the load growth in the Green Valley area for loss of the South-Green Valley 138kV circuit beyond the 2013 to 2016 time frame.

f. TEP is in the process of gathering this information and will provide it as soon as possible.

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

h. The project was constructed by a combination of TEP employees and contractors. There were no safety concerns or incidents related to this project.

1. Civil and Physical construction was bid out to four contractors, two bids were received and compared on price and schedule.
2. TEP supplied inspectors for oversight of contractor work to provide access and ensure quality of work.
3. No capital work was deferred to allow this project to be completed

i. The power distribution center (PDC) was assembled off-site by the manufacturer at their site. All other equipment was constructed on site.

j. No delays.

k. As-built drawings have been completed.

l. Substation Engineering provided standard testing procedures and the procedures were followed prior to commissioning the equipment.

m. The transformer and breakers were purchased with a warranty from the manufacturer.

n. The following maintenance procedures have been established for battery and GCB (gas circuit breaker) additions:

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1. Quarterly battery inspection/maintenance.
2. 3 year GCB inspections.
3. Annual infrared inspections.
4. Inspection every 4 months during the major sub inspection.

o. No, the extra maintenance is absorbed in our annual O&M budget.

p. One outage due to improper relay settings. This has been remediated.

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. The retirement and cost of removal associated with this project occurred as a result of replacement or obsolescence during construction of new assets. Please see table 3 in file "STF 6.01 - 6.25 Project Details.xlsx".

t. TEP did not notify FERC or seek approval for the referenced projects. FERC does not require pre-approval of projects.

u. TEP did not file any claims with any of our insurers for this project.

RESPONDENT:

Randy Deming (a, d, g, q-s) and Ana Bustamante (b, c, e, f, h-p, t, u)

WITNESS:

Frank Marino and Susan Gray

SUPPLEMENTAL RESPONSE: March 21, 2016

f. The project was estimated at $5.4M and came in under budget due to cost savings with combining civil and physical construction bids.

RESPONDENT:

Ana Bustamante (f)

WITNESS:

Susan Gray

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STF 6.18

Plant Additions:

Please provide the following information for the plant addition abbreviated as D09BB04 Can Rnch - Duval Cir 138kV Line.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

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r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE:

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

b. Transmission Planning and Distribution Planning determined that the underlying 46kV system will not have adequate transformer capacity to support the load growth in the Green Valley area for loss of the South-Green Valley 138kV circuit beyond the 2013 to 2016 time frame. Extending the 138kV to FMI-Sierrita (Canoa Ranch-Duval Clear 138kV project) allows for continuity of service for loss of a 138kV circuit in Green Valley.

c. The project was budgeted and the approval was part of the annual capital budget approval process.

d. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

e. Transmission Planning and Distribution Planning determined the underlying 46kV system would not have adequate transformer capacity to support the load growth in the Green Valley area for loss of the South-Green Valley 138kV circuit beyond the 2013 to 2016 time frame.

f. The project was estimated at $6.7M and came in under budget due to cost savings realized from cranes, foundations, and internal labor.

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

h. This project was constructed by both TEP employees and contractors. TEP employees constructed the 138 kV line and the contractor provided installation of foundations.

1. TEP received outside bids to perform the installation of foundations that went through the Company's competitive bidding process. TEP is unable to provide the actual bids without approval of the contractor due to the competitively sensitive confidential nature of the bidding process.
2. Oversight was provided by a TEP employed Construction Manager.
3. No capital work was deferred to allow this project to be completed.

i. All portions of this project were constructed on-site.

j. No delays.

k. As-built drawings have been completed.

l. The line was inspected for conformity to specifications, phasing was checked, and then released to operations for use.

m. No equipment was purchased that required warranties.

n. Yearly line patrols.

o. No, the extra maintenance is absorbed in our annual O&M budget.

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p. No outages related to the project since the in-service date.

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. No retirement or cost of removal are recorded for this project.

t. TEP did not notify FERC or seek approval for the referenced projects. FERC does not require pre-approval of projects.

u. TEP did not file any claims with any of our insurers for this project.

RESPONDENT:

Randy Deming (a, d, g, q-s) and Ana Bustamante (b, c, e, f, h-p, t, u)

WITNESS:

Frank Marino and Susan Gray

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STF 6.19

Plant Additions:

Please provide the following information for the plant addition abbreviated as D05AG01 Deming Luna Project.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

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r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE:

TEP is in the process of gathering this information from PNM and will provide it as soon as possible.

RESPONDENT:

Diane Grant (a, d, g, q-s) and John Baum (b, c, e, f, h-p, t, u)

WITNESS:

Frank Marino and Susan Gray

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STF 6.20

Plant Additions:

Please provide the following information for the plant addition abbreviated as D05AG01 D08BB76 DMP-Tucson 138kV Ln.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

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r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE: **March 18, 2016**

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

b. The existing 46kv tie between the DeMoss Petrie and Tucson Substation was not adequate to support voltage at the 138kV buses at West Ina, Camino Del Cerro and Tucson Substation for the double contingency involving loss of the Irvington-Tucson and North Loop-West Ina 138kV lines. The purpose of the DMP to Tucson project was to add a new 138kV transmission path to provide voltage support in the event of a multiple contingency that would result in the Tucson Station, Camino del Cerro and West Ina substations all being supplied over the new line from DMP substation and eliminate the voltage instability.

c. The project was budgeted and the approval was part of the annual capital budget approval process.

d. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

e. This project was needed to comply with voltage requirements in the NERC Planning standards and WECC System Performance Criteria.

f. TEP is in the process of gathering this information and will provide it as soon as possible.

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

h. This project was constructed by both TEP employees and contractors. TEP employees constructed the 138 kV line and the contractor provided installation of foundations. During the installation of a foundation near Tucson substation, an unidentified underground tank was encountered. The tank was abandoned and after proper testing and notification of government agencies, the tank was filled with concrete slurry. The foundation was installed after the tank was remediated. Union Pacific Railroad (UPRR) raised concern of the impact of a high voltage line on their adjacent rail. A counterpoise ground was installed to mitigate their concerns.

   1. TEP received an outside bids to perform the installation of foundations that went through the Company's competitive bidding process. TEP is unable to provide the actual bids without approval of the contractor due to the competitively sensitive confidential nature of the bidding process.
   2. Oversight was provided by a TEP employed Construction Manager and a contracted inspector.
   3. No capital work was deferred to allow this project to be completed.

i. Only major material, such as transmission poles, conductor, insulators, were constructed off-site.

j. Minor delays due to Union Pacific Railroad (UPRR) permit and requirements.

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k. As-built drawings have been completed.

l. The line was inspected for conformity to specifications, phasing was checked, and then released to operations for use.

m. No equipment was purchased that required warranties.

n. Yearly line patrol.

o. No, the extra maintenance is absorbed in our annual O&M budget.

p. No outages related to the project since the in-service date.

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. The retirement and cost of removal associated with this project occurred as a result of replacement or obsolescence during construction of new assets. Please see table 3 in file "STF 6.01 - 6.25 Project Details.xlsx".

t. TEP did not notify FERC or seek approval for the referenced projects. FERC does not require pre-approval of projects.

u. TEP did not file any claims with any of our insurers for this project.

RESPONDENT:

Randy Deming (a, d, g, q-s) and Ana Bustamante (b, c, e, f, h-p, t, u)

WITNESS:

Frank Marino and Susan Gray

SUPPLEMENTAL RESPONSE: March 21, 2016

f. The project was estimated at $5.0M. Adjustments were made during the project to meet the project schedule per CEC requirements.

RESPONDENT:

Ana Bustamante (f)

WITNESS:

Susan Gray

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STF 6.21

Plant Additions:

Please provide the following information for the plant addition abbreviated as D10GN10 NL 138kV Yard Expansion Ph 3.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

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r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE:

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

b. Phase 3 of the North Loop substation expansion was to accommodate the increased 138kV transmission capacity between Tortolita substation and North Loop substation.

c. The project was budgeted and the approval was part of the annual capital budget approval process.

d. This project consists of several distinct construction efforts which have independent completion dates. Please see Table 2 in file "STF 6.01 - 6.25 Project Details.xlsx".

e. The North Loop substation expansion was needed to accommodate the increased 138kV transmission capacity between Tortolita substation and North Loop substation.

f. The project was estimated at $6.5M. Miscellaneous adjustments were made during the project.

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

h. Work was completed by both TEP and contractors. One safety incident where a steel plate was dropped on employees steel toe boot, causing a hair line fracture in his pinky toe.

1. TEP received an outside bids to perform work that went through the Company's competitive bidding process. TEP is unable to provide the actual bids without approval of the contractor due to the competitively sensitive confidential nature of the bidding process.

2. Oversight was provided by a TEP employed Construction Manager and a contracted inspector.

3. No capital work was deferred to allow this project to be completed.

i. All equipment was constructed on-site.

j. No delays.

k. As-built drawings have been completed.

l. Substation Engineering provided standard testing procedures and the procedures were followed prior to commissioning the equipment.

m. The breakers were purchased with a warranty from the manufacturer.

n. The following maintenance procedures have been established for GCB (gas circuit breaker) additions:

1. 3 year GCB inspections.

2. Annual infrared inspections.

3. Inspection every 4 months during the major sub inspection

o. No, the extra maintenance is absorbed in our annual O&M budget.

p. No outages related to the project since the in-service date.

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. The retirement and cost of removal associated with this project occurred as a result of replacement or obsolescence during construction of new assets. Please see table 3 in file "STF 6.01 - 6.25 Project Details.xlsx".

t. TEP did not notify FERC or seek approval for the referenced projects. FERC does not require pre-approval of projects.

u. TEP did not file any claims with any of our insurers for this project.

RESPONDENT:

Randy Deming (a, d, g, q-s) and Ana Bustamante (b, c, e, f, h-p, t, u)

WITNESS:

Frank Marino and Susan Gray

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STF 6.22

Plant Additions:

Please provide the following information for the plant addition abbreviated as D111WMC T&D Work Mgmt Consolidation Ph1

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE:

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

b. This was the first phase of a multi-phase software project to consolidate multiple sources of work and asset management information, processes, and software applications into a single software solution based on "best practice" in the Transmission and Distribution (T&D) operations area. The initial phase focused on the assets (equipment) and work processes in the Substations, Relay, Communications, Transmission Maintenance, Electric Repair and Test Facility, Vegetation Management and the Protective Goods Lab. These are asset intensive areas with work processes that were developed around disparate support systems. Phase 1 of this project targeted the consolidation of the following computer software systems:

- MP2, an obsolete, vendor named and supplied software application installed in 1994 and last updated in 2002. It was used primarily by Substations, Relay, Communication and Transmission Maintenance.
- ERTF, (Electronic Repair and Test Facility) an internally developed MSAccess software application installed in 1995 and used to track the repair and maintenance of distribution assets including transformers, switchgear and regulators.
- Consignment, an internally developed MSAccess software application installed to manage the pre-receiving process for transformers before they are accepted into inventory.
- Protective Goods, an internally developed software application installed in 1997 and used to track the testing of safety equipment including rubber gloves, hot sticks and rubber mats.

c. The project was included in the capital budget and approved on 3/30/11 by the IT Executive Steering Committee. Minutes are attached in the Appendix.

d. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

e. Justification benefits are listed below from the March 30, 2011 IT Executive Steering Committee Presentation:

- Provide an alternative to manual review of maintenance records related to NERC compliance
- Establishes a foundation for reliability based maintenance
- One "go to" location for information, analysis and metrics
- Shared visibility of work for planning and forecasting

- Consistency of work processes, end-to-end
- A single integration point between corporate systems and operational needs
- Configurable Security and Work Flow to respond to changing regulatory requirements as well as internal audit controls and process changes
- Leverage expanding in-house resources for support.
- Ability to incorporate rules based monitoring and notifications to avoid work "slipping through the cracks"

The presentation notes also made reference to the need to replace technologically obsolete computer software systems.

f. Project Capital budget projected: $3,415,789

Project Capital Actuals: $3,386,333

Project completed within the capital budget. No changes orders were processed.

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

h. There were no safety incidents or concerns on this project. Internal and external labor were used in the design, development, and implementation of the software project:

1. TEP received an outside bids to perform work that went through the Company's competitive bidding process. TEP is unable to provide the actual bids without approval of the contractor due to the competitively sensitive confidential nature of the bidding process.
2. Several rounds of testing were performed, during which each deliverable provided by a contractor was thoroughly tested and approved for implementation.
3. There was no capital/expense work deferred for internal employee resources.

i. There were no parts or deliverables for the project constructed or assembled off-site.

j. There were no delays during the project.

k. 'As built' process documentation for the software, configuration, and data migration were delivered with the completion of the project.

l. Extensive testing of the configured software and custom components was performed in several test cycles.

Testing Processes:

A formal Test Plan document was drafted to provide the framework for testing processes and efforts. A Defect Management Plan document was drafted to track defect mitigation. Formal Test Scripts for all primary business functions (identified in Business Process and To Be work sessions) were developed and executed by Business testers. Integration Test Cases were developed and executed to vet the accuracy and completeness of all inter-system integrations.

Testing Practices

1. Unit Testing: Was performed by developers as each component or customization was completed
2. Integrated System Testing: Was performed iteratively to ensure all components and customizations worked together

3. Acceptance Testing: Was performed by T&D Business users (as well as other business units in support of integrations with other software systems), executing test scripts, over two full test cycles

4. Mock Cut-Over: Performed two full formal rounds by executing the cut-over task list; an initial practice was executed, the task list refined, and then performed the formal Mock 1 and Mock 2 cut-over exercises.

m. No computer hardware was purchased.

n. The computer software does not require any ongoing scheduled maintenance procedures.

o. Yes, we pay IBM, the software vendor, annual maintenance (approximately $30k -$35k annually) to maintain support of our software licenses.

p. There were no power outages that occurred as a result of this project. There were computer application software outages that occurred when the software was initially installed in the Company's computer production network. There are ongoing periodic routine application outages to reboot the application system.

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. No retirement or cost of removal are recorded for this project.

t. The Company was not required to notify FERC or receive FERC approval. This was a project to install software. No transmission upgrades or changes were made.

u. No insurance claims were filed for this project.

RESPONDENT:

David Cada (a, d, g, q-s) and Tom Comparato (b, c, e, f, h-p, t, u)

WITNESS:

Frank Marino and Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
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STF 6.23

Plant Additions:

Please provide the following information for the plant addition abbreviated as D14RI02 Ft Huachuca – Solar.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

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r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE:

Please see TEP's responses to STF 6.09. This is a duplicate question.

RESPONDENT:

Wanda Nerney (a, d, g, q-s) and Carmine Tilghman (b, c, e, f, h-p, t, u)

WITNESS:

Frank Marino / Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
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STF 6.24

Plant Additions:

Please provide the following information for the plant addition abbreviated as D13SB06 Main Access Road Construction.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

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r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE:

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

b. This project was to replace 30-year-old asphalt pavement on the main access road to the plant.

c. Yes, project was included in approved capital budget.

d. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

e. This task was justified for reasons of safety and reliability.

f. Cost estimates were included in the capital approval documentation.

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

h. 1. TEP received outside bids to perform the work, which went through the Company's competitive bidding process. TEP is unable to provide the actual bids without approval of the contractors due to the competitively sensitive confidential nature of the bidding process.

2. A contractor performed this work. Company engineer provided contractor oversight.

3. None.

i. Construction was performed entirely on-site. Asphalt mixed off-site and hauled to site.

j. No delays due to parts availability, labor availability, weather, design constraints, permitting or unanticipated problems.

k. As-built drawings completed as required.

l. Road base and asphalt pavement were tested by a 3rd party per ADOT standards.

m. New road warrantied by contractor.

n. Maintenance procedures have been scheduled within appropriate maintenance system.

o. Yes

p. None

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. No retirement or cost of removal are recorded for this project.

t. No FERC approval required.

u. No Insurance Claims

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RESPONDENT:
Randy Deming (a, d, g, q-s) and Pat Fahey (b, c, e, f, h-p, t, u)
WITNESS:
Frank Marino and David Hutchens

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
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STF 6.25

Plant Additions:

Please provide the following information for the plant addition abbreviated as D13NM12 Grant T1 46kV Sub Xfmr Replc.

a. The full name of the project.

b. A narrative describing the reason(s) for the project.

c. Was the project included in an approved capital budget and if so provide that approval.

d. Start date of the project and completion date of the project.

e. Any engineering determination justifying the project including any cost benefit analysis and Net Present Value analysis or Internal Rates of return.

f. A history of the project cost estimates and the reasons for any changes (include dates and appropriate approvals based on the applicable LOSA document).

g. Please provide the project cost detail by type (i.e., payroll, contractor costs, M&S, overheads, AFUDC, from the Company plant accounting system.

h. Indicate if the project was constructed by company employees, contractors or a combination. Also detail any safety concerns and/or incidents that occurred related to the project.

   1. If all or a portion of the project was performed by outside contractors please provide the bid analysis that concluded which contractors should be selected.

   2. If contractors were used please describe what oversight was provided by the Company.

   3. If Company employees were used for the project please explain what capital/expense work was deferred, if any, to allow this to be done.

i. Indicate the extent that portions of the project were constructed or assembled off-site and then installed fully or partially on-site.

j. Explain any delays due to parts availability, labor availability or work stoppages, weather, design constraints, permitting or any other unanticipated problem. Explain the duration of those delays and, if applicable, AFUDC was stopped.

k. Indicate if "as-built" drawings/records have been completed.

l. Indicate whether the project was tested before being placed in-service and describe the testing process and criteria used to declare the project used and useful.

m. If equipment was purchased from the outside (transformers etc.) were those purchases warrantied by the mfg. and if not, why not.

n. Describe and indicate whether the required maintenance procedures have been scheduled within the appropriate maintenance system.

o. Did subsequent budgets reflect a change in O&M based on the installation of new assets?

p. Provide any details of any outages related to the project since the in-service date.

q. Provide the accounting details and adjustments made to move the project into plant in service; when these adjustments were made; any subsequent adjustments made and why (including dates). Also indicate when the project was unitized.

r. Provide supporting information for any salvage values including the ultimate disposition of unneeded or removed items and how the salvage was accounted for within the project.

s. Provide supporting information for any retirements including the reasons for the retirements, when the retirements were recorded and what the associated cost of removal was.

t. Was the Company required to notify FERC, or receive FERC approval, for any transmission upgrades or changes? If so please provide that approval and if not why not?

u. Were any insurance claims filed for the project and if so were they received and how were they accounted for?

RESPONSE:

a. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

b. This project consisted of the design, procurement, construction and commissioning of a new transformer to replace the existing 46kV, 7.5/9.4 MVA transformer due to the existing transformer having reached the end of its useful life.

c. The project was budgeted and the approval was part of the annual capital budget approval process.

d. This project consists of several distinct construction efforts which have independent completion dates. Please see Table 2 in file "STF 6.01 - 6.25 Project Details.xlsx".

e. The existing transformer was identified as a candidate for replacement by maintenance engineering due to the oil quality, paper insulation quality, deteriorated low and high side winding insulation, and age of the transformer.

f. The project was estimated at $2.3M. Miscellaneous adjustments were made during the project.

g. See Table 1 in the file "STF 6.01 - 6.25 Project Details.xlsx".

h. Work was completed by both TEP and contractors. Company employees constructed the substation physical and electrical and the contractor provided demolition and civil construction services. No safety concerns or incidents occurred during this project.

1. The civil work was sole-sourced and TEP sole-sourced justification procedures were followed.

2. TEP supplied inspectors for oversight of contractor work to provide access and ensure quality of work.

3. No capital work was deferred to allow this project to be completed.

i. The transformer required assembly at the manufacturer site but everything else was constructed on site.

j. There was minor material delays but the project was completed on time.

k. As-built drawings have been completed.

l. Substation Engineering provided standard testing procedures and the procedures were followed prior to commissioning the equipment.

m. The transformer and breakers were purchased with a warranty from the manufacturer.

n. The following maintenance procedures have been established:

   1. Doble (set of diagnostic tests that prove integrity of the transformer) and sudden pressure relay testing after 1yr, 3yrs, 5yrs.

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2. Monthly warranty inspection for first five years.
3. Annual infrared inspections.
4. Annual Dissolved Gas Analysis (DGA) tests.
5. Annual Inspection during distribution sub inspection.
6. Quarterly battery inspection/maintenance.

o. No, the extra maintenance is absorbed in our annual O&M budget.

p. No outages related to the project since the in-service date.

q. There are two types of methods in which assets can be transferred from CWIP to PIS – manual unitization and blanket unitization. Each method results in a journal entry transferring assets from CWIP to PIS in the Plant Accounting system.

r. No salvage amounts were recorded for this project.

s. The retirement and cost of removal associated with this project occurred as a result of replacement or obsolescence during construction of new assets. Please see table 3 in file "STF 6.01 - 6.25 Project Details.xlsx".

t. TEP did not notify FERC or seek approval for the referenced projects. FERC does not require pre-approval of projects.

u. TEP did not file any claims with any of our insurers for this project.

RESPONDENT:

Dominic Carter (a, d, g, q-s) and Cynthia Garcia (b, c, e, f, h-p, t, u)

WITNESS:

Frank Marino and Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S THIRTEENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
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From the visit to Springervile Generating Station

STF 13.1

SGS Common O&M:

a. Please confirm that the energy output of the solar arrays at the Station is used to supply the energy to the pumps in the well field which provide water to all four units at SGS.

b. Please provide a description of how the energy output from the Company's solar resources at the station are accounted for with respect to the operations expense for the Station for the well field operations. Specifically, provide documentation showing how TEP and its customers are compensated for the energy generated by the solar arrays at the SGS site that is used by the common well field facilities. Please provide an accounting of this compensation for 2012, 2013, 2014 and 2015.

RESPONSE:

a. Solar is used for well field.

b. Solar production is part of in kind energy journal J317, with 25% to each unit.

The total auxiliary power is calculated each month by taking 22 different meters plant wide to arrive at total quantity. The solar power generation is one of the 22 meters. MW are then converted to dollars based on the prior month rate. To get only the solar amount would require extensive time to retrieve each month of each year Journal 317. Here is a sample of solar generation: Jan 2015 was 950 MW and Aug 2015 was 1575 MW

The solar is a piece of the total journal entry. The following are the accounting entries for the participants (U1 Alterna, U1 LDVF1, U3 Tristate and U4 SRP) is to:

Debit account 11350 Other Accounts Receivable for U1 and 11050 Wholesale sales for U3 and U4

Credit account 40250 Reserve sharing.

The portion of MW that are charged to U1 Alterna and U1 LDVF1 are included on their monthly invoice. It should be noted that we have included solar generation MW on each monthly invoice to Alterna and LDVF1 but both companies are currently in arrears for all of 2015 and to date 2016. The MW for U3 and U4 are tracked and TEP receives MW in return in a future period.

Documentation of accounting:

Source J317 for 2012-2013-2014-2015

Legend

Account		Explanation
11050		Unit 3 + 4 net which equals MW used less MW returned to TEP in dollars
11350		U1 participants MW used in dollars
40250		U3 + 4 MW Used for 2012-2014. As of 1/15 MW used by participants of U1, U3, U4, in dollars
		U3+U4 MW returned to TEP, in dollars

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51230		

Sum of Amount SUM		
GI Period Name	Acct	Total
APR-12	11050	40,147.09
	40250	(69,507.57)
	51230	29,360.48
APR-12 Total		(0.00)
APR-13	11050	1,466.71
	40250	(89,012.49)
	51230	87,545.78
APR-13 Total		0.00
APR-14	11050	(35,705.16)
	40250	(58,618.12)
	51230	94,323.28
APR-14 Total		0.00
APR-15	11050	(38,072.90)
	11350	226,988.49
	40250	(302,851.07)
	51230	113,935.48
APR-15 Total		0.00
AUG-12	11050	133,634.40
	40250	(173,000.31)
	51230	39,365.91
AUG-12 Total		0.00
AUG-13	11050	(34,173.49)
	40250	(99,117.56)
	51230	133,291.05
AUG-13 Total		0.00
AUG-14	11050	23,820.23
	40250	(106,804.58)
	51230	82,984.35
AUG-14 Total		0.00
AUG-15	11050	(7,040.15)
	11350	268,080.19
	40250	(365,185.36)
	51230	104,145.32
AUG-15 Total		0.00
DEC-12	11050	15,178.69
	40250	(99,893.02)
	51230	84,714.33

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DEC-12 Total		0.00
DEC-13	11050	129,388.38
	40250	(94,736.28)
	51230	(34,652.10)
DEC-13 Total		0.00
DEC-14	11050	3,419.88
	40250	(84,144.47)
	51230	80,724.59
DEC-14 Total		0.00
DEC-15	11050	(42,240.58)
	11350	225,149.19
	40250	(297,690.28)
	51230	114,781.67
DEC-15 Total		(0.00)
FEB-12	11050	11,817.76
	40250	(85,708.96)
	51230	73,891.20
FEB-12 Total		0.00
FEB-13	11050	(150,732.22)
	40250	(82,513.44)
	51230	233,245.66
FEB-13 Total		(0.00)
FEB-14	11050	47,819.68
	40250	(82,127.23)
	51230	34,307.55
FEB-14 Total		0.00
FEB-15	11050	(6,078.36)
	11350	275,295.48
	40250	(361,738.21)
	51230	92,521.09
FEB-15 Total		(0.00)
JAN-12	11050	(16,506.34)
	40250	(69,613.51)
	51230	86,119.85
JAN-12 Total		0.00
JAN-13	11050	7,890.01
	40250	(95,891.67)
	51230	88,001.66
JAN-13 Total		(0.00)

Arizona Corporation Commission ("Commission")
Fortis Inc. ("Fortis")
Tucson Electric Power Company ("TEP" or the "Company")
UNS Energy Corporation ("UNS")

UniSource Energy Services ("UES")
UniSource Energy Development Company ("UED")
UNS Electric, Inc. ("UNS Electric")
UNS Gas, Inc. ("UNS Gas")

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S THIRTEENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
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JAN-14	11050	(79,359.70)
	40250	(82,432.62)
	51230	161,792.32
JAN-14 Total		0.00
JAN-15	11050	5,044.35
	11350	209,243.26
	40250	(274,447.37)
	51230	60,159.76
JAN-15 Total		0.00
JUL-12	11050	(124,636.63)
	40250	(110,558.84)
	51230	235,195.47
JUL-12 Total		0.00
JUL-13	11050	6,834.30
	40250	(114,162.30)
	51230	107,328.00
JUL-13 Total		0.00
JUL-14	11050	(4,739.82)
	40250	(132,799.84)
	51230	137,539.66
JUL-14 Total		0.00
JUL-15	11050	34,636.85
	11350	268,080.19
	40250	(363,867.33)
	51230	61,150.29
JUL-15 Total		(0.00)
JUN-12	11050	(17,606.75)
	40250	(96,837.55)
	51230	114,444.30
JUN-12 Total		0.00
JUN-13	11050	15,281.86
	40250	(98,489.85)
	51230	83,207.99
JUN-13 Total		0.00
JUN-14	11050	18,599.89
	40250	(101,598.84)
	51230	82,998.95
JUN-14 Total		0.00
JUN-15	11050	26,924.48
	11350	274,758.34

Arizona Corporation Commission ("Commission")
Fortis Inc. ("Fortis")
Tucson Electric Power Company ("TEP" or the "Company")
UNS Energy Corporation ("UNS")

UniSource Energy Services ("UES")
UniSource Energy Development Company ("UED")
UNS Electric, Inc. ("UNS Electric")
UNS Gas, Inc. ("UNS Gas")

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S THIRTEENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 21, 2016

	40250	(372,370.18)
	51230	70,687.36
JUN-15 Total		(0.00)
MAR-12	11050	3,584.75
	40250	(71,980.27)
	51230	68,395.52
MAR-12 Total		0.00
MAR-13	11050	159,282.54
	40250	(111,949.95)
	51230	(47,332.59)
MAR-13 Total		0.00
MAR-14	11050	33,925.29
	40250	(98,177.41)
	51230	64,252.12
MAR-14 Total		0.00
MAR-15	11050	(10,048.98)
	11350	270,625.87
	40250	(356,358.65)
	51230	95,781.76
MAR-15 Total		(0.00)
MAY-12	11050	(22,319.78)
	40250	(88,703.81)
	51230	111,023.59
MAY-12 Total		0.00
MAY-13	11050	72,344.04
	40250	(98,330.51)
	51230	25,986.47
MAY-13 Total		0.00
MAY-14	11050	22,906.57
	40250	(81,193.44)
	51230	58,286.87
MAY-14 Total		0.00
MAY-15	11050	(13,710.19)
	11350	268,556.37
	40250	(354,235.46)
	51230	99,389.28
MAY-15 Total		(0.00)
NOV-12	11050	(14,444.38)
	40250	(80,645.07)
	51230	95,089.45

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S THIRTEENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 21, 2016

NOV-12 Total		0.00
NOV-13	11050	(85,815.45)
	40250	(82,119.58)
	51230	167,935.03
NOV-13 Total		0.00
NOV-14	11050	13,044.38
	40250	(76,543.04)
	51230	63,498.66
NOV-14 Total		0.00
NOV-15	11050	(19,344.46)
	11350	245,183.66
	40250	(322,186.00)
	51230	96,346.80
NOV-15 Total		(0.00)
OCT-12	11050	(109,522.39)
	40250	(99,939.59)
	51230	209,461.98
OCT-12 Total		0.00
OCT-13	11050	59,364.84
	40250	(105,510.85)
	51230	46,146.01
OCT-13 Total		0.00
OCT-14	11050	18,633.91
	40250	(84,566.98)
	51230	65,933.07
OCT-14 Total		0.00
OCT-15	11050	(17,820.35)
	11350	243,630.84
	40250	(326,742.92)
	51230	100,932.43
OCT-15 Total		0.00
SEP-12	11050	25,681.43
	40250	(108,611.52)
	51230	82,930.09
SEP-12 Total		0.00
SEP-13	11050	(4,963.38)
	40250	(97,485.48)
	51230	102,448.86
SEP-13 Total		0.00

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TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S THIRTEENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 21, 2016

SEP-14	11050	(54,713.60)
	40250	(91,740.80)
	51230	146,454.40
SEP-14 Total		0.00
SEP-15	11050	18,933.13
	11350	278,574.42
	40250	(379,454.00)
	51230	81,946.45
SEP-15 Total		0.00
Grand Total		(0.00)

RESPONDENT:

Carolyn Rice

WITNESS:

Frank Marino

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S NINTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 28, 2016

STF 9.7

Line Losses – Follow-up to STF 1.35. Provide the line losses for each calendar year, 2013, 2014, and 2015 for the following categories: 345kV, 138 kV, Transformer and Distribution. Provide any studies that the Company has prepared where the Company considered ways to mitigate line losses.

RESPONSE:

The Company has not completed a line loss study other than what has been already provided in this case, therefore the following table represents the information filed in the Company's annual FERC Form 1 for the requested time periods. The Company is always working towards mitigating system losses through upgrades and improvements however no specific studies have been conducted.

(in MWH)	2013	2014	2015
Transmission Losses	409,286	325,999	365,108
Distribution Losses	464,102	498,480	444,034
Total Losses	873,388	824,479	809,142

RESPONDENT:

Jeanine Tracey / Brenda Pries

WITNESS:

Craig Jones

Estimating Distribution losses

In order to estimate the distribution losses, first we identify feeder circuits which have a sufficiently high number of associated meters for which we have interval data. We then select a time interval and calculate the load at the feeder as well as the aggregate load for all the meters on that same feeder circuit. Not every meter has quality interval data, for those meters we calculate an average hourly usage based on last month's bill. The distribution loss is then the load at the feeder minus the aggregate load of the meters plus the estimated load for meters without quality interval data.

Sampled Distribution losses

Substation	Circuit	Circuit Eff	Loss %	ID Saturation	High Quality ID	Low Quality ID	Total
Bopp Donald	BD-1	94.91	5.09	94.2	1795	111	1906
East Loop	EA-55	94.5	5.5	95.02	922	80	1002
South Loop	SOSU-612	92.9	7.1	87.3	2596	373	2969
West Ina	WI-27	92.2	7.8	84.5	1320	241	1561

Estimating Transmission losses (345 kV and 138 kV)

This portion of the line loss study was conducted using two different methods corresponding to the two different portions of TEPs transmission system. One method, which leverages data found in our MDM (Meter Data Management) system, is used to estimate the losses on TEP's 345 kV system – the other method uses data from EMS to estimate the losses on TEP's 138 kV system.

Estimating 345 kV losses

The method for estimating TEP's 345 kV losses are pretty straight forward. For every line in TEP's 345 kV system (for which we have data), calculate the difference between the delivered and received channels of the meters at each end of the line. The 345 kV losses are then the sum of the differences of these metered points.

Estimating 138 kV losses

The approach we took to estimate the 138 kV losses is not as straight forward as the 345 kV method. Initially we attempted to use a method similar to the 345 kV calculation but discovered that we don't

have measurement devices installed at both ends of the 138 kV line in some cases. This deficiency has been identified, and as a result, our metering standard has been updated.

The method we eventually decided on is one where we take the *city import*[i] values along with any sources of generation on the 138 kV system[ii] and subtract from that, the sum of all the measurements at the "high side" of the 138 kV distribution transformers.

Estimating Transformer losses

Transformer losses are estimated to contribute an additional .3% to the transmission losses based on the results of this analysis: G:\ENGINEER\LossStudy\TransformerLossStudy

Summary

Based on the above methodology, data available and the data sampled, we estimate our total system losses to be approximately 11% based on the following assumptions:

345 kV loss – 2%

138 kV loss – 3%

Transformer loss - 0.3%

Distribution loss – 6%

Note: Error in the measurement devices used to compute these losses were not accounted for in the above methods.

[i] The city import value is comprised of the measurements at the Saguaro L1, Saguaro L2, South Loop T2, South Loop T3, Vail T1, Vail T2 and Vail T3.
[ii] Sources of generation on 138 kV system were determined to be Sundt units 3 and 4 along with Sundt ICTs 1 and 2 at the Irvington generation station along with the ICT at DeMoss Petrie.

Capital
UNS Consolidated
CC_UNS high level hierarchy
BC_UNS
Activity
FERC
Location
SubAccount
ET_A03 Directs Loads & Indirects

	2012 YearTotal Actual	2013 YearTotal Actual	2014 YearTotal Actual	2015 Jun YTD Actual	TOTAL
D07GV02 Craycroft Barril 138kV Sub L&E	7,543	-3,165	0	0	4,378
SUBS101 Barril Substation	7,543	-3,165	0	0	4,378
D06IR01 Canoa Ranch Land Purch	123,929	166	0	0	124,094
D06IR02 Canoa Ranch 138kV Sub	32,650	0	-16,285	0	16,365
D07BB67 Gm Vly 138kV Line Term C Rnch	335,025	7,538	0	0	342,563
D11LD95 Canoa Ranch Fdr Ties	-294	0	0	0	-294
SUBS102 Canoa Substation	491,310	7,704	-16,285	0	482,729
D07BB51 Irv 138kV Cap Banks & Bus Ext	-747	0	0	0	-747
D08BB93 Vail 138kV Cap Banks	34	0	0	0	34
D14BB59 Rillito Cap Bank No 1 Upgd	0	0	93,619	0	93,619
D14BB60 South Cap Bank No 1 Upgd	0	0	0	56,111	56,111
D14BB61 Irv Ring Cap Bank No 1 Upgd	0	0	15,031	0	15,031
D14BB62 Irv Ring Cap Bank No 2 Upgd	0	0	26,537	83,529	110,066
D14BB63 Canoa Ranch Cap Bank	0	0	0	65,813	65,813
SUBS103 Capacitor Bank	-713	0	135,187	205,453	339,926
D09GL14 Rancho Vistoso Transformer Addn	1,947,696	-430	0	0	1,947,266
D10LD94 Rancho Vistoso T3 Fdr Ties	1,307,712	432,757	174,864	-113,709	1,801,624
D10SG27 Rancho Vistoso T3 Sub Getaways	927,031	10,860	0	0	937,891
SUBS104 Sun City - Rancho Vistoso Substation	4,182,438	443,188	174,864	-113,709	4,686,781
D06IN01 Wentworth Land Purchase	-469	0	0	0	-469
D06IN03 Cienega Land Purchase	-2,021	0	0	0	-2,021
SUBS105 Cienega Substation	-2,490	0	0	0	-2,490
D08BP01 Vail T3 345/138kV Xfmr Add	3,379,703	195,976	-9,330	0	3,566,350
SUBS106 Vail Expansion	3,379,703	195,976	-9,330	0	3,566,350
D06FN03 Camino Del Cerro 138kV Sub	-69	0	0	0	-69
SUBS108 Del Cerro	-69	0	0	0	-69
B01001C Raptor-Related Repl & Bettrmnt	594,003	652,104	693,929	613,397	2,553,434
CBONH02 Distribution Capacitors	418,075	203,251	450,449	33,771	1,105,545
CBONL01 Distr Feeders & Ties	-147,650	18,668	-88,364	-58,098	-275,444
CBONL84 Distribution Lines-New	697,462	17,733	704,833	27,626	1,447,654
CBONX01 Dist Lines -Repl & Bettr	1,559,823	2,560,526	2,003,164	621,076	6,744,589
CBOSA00 Distr Circuit Lightning Protection	-309	0	0	0	-309
D08LD47 E Lp C15 C-17 Reconductor	431,328	39,926	-76,067	0	395,187
D08LD55 Midvale Fdr Imprvmnts C-6 8 9	121	0	0	0	121
D09LD60 Robert Bills Fdr Imprvmnts C-17	0	331,229	0	0	331,229
D09LD62 West Ina C-29 Reconductor	0	198,634	0	0	198,634
D09LD65 Vail C-7 Extension to Target	-28,260	1,620	0	0	-26,641
D10EB07 Irvington Tie Cables	0	522,150	55,748	0	577,898
D10LD71 Contractor Way 14kV Dist Reloc	-14,269	0	0	0	-14,269
D10LD72 Santa Cruz C-8 Reconductor	328,469	0	0	0	328,469
D10LD76 R Bills C-14 Recond & Fdr Tie	0	362,815	0	0	362,815
D10LD91 Dist Clearance Resolutions	11,868	292,628	-17,302	0	287,193
D10LD93 21st St New Fdr & Rbld	227	102	0	0	329
D11LD05 Valencia Road Rebuild	74,701	0	0	0	74,701
D11LD08 Tucson Cntry Club Volt Imprv Ph 1	319	0	0	0	319
D11LD96 DMP C-22 Reconductor	325,122	0	0	0	325,122
D11LD98 DT Vault 38 ATO Rplc	81,005	0	0	0	81,005
D11SG30 Canoa Ranch C18 Sub Getaway	1,101,994	1,365,078	0	0	2,467,072
D12LD09 Tucson Cntry Club Volt Imprv Ph 2	213,006	-22,992	0	0	190,014
D12LD10 STZ C-11 Recon:Congress-Grande	482,205	0	0	0	482,205
D12LD11 Canoa Ranch C18 Fdr Tie	204,370	500,633	0	0	705,002
D12LD12 Indian School Voltage Improv	155,001	0	0	0	155,001
D12LD19 13.8kV Smart Switch Installations	91,007	113,956	61,037	-7,567	258,433
D13LD37 Serv to Salpointe OH Conv	0	0	741,497	0	741,497
D13LE28 RV- Tangerine West 3rd Fdr Tie	0	241,030	919,882	-478,490	682,422
D13LE29 RV- Tangerine West 3rd Fdr Gtawys	0	453,212	60	0	453,272
D13SG32 West Ina Getaways	0	215,772	0	0	215,772
D13SG33 Olive T1 Sub Getaways	0	0	0	24,906	24,906

Run Date 5/27/16 8:13 AM

D13SG34 Grant T1 Sub Getaways	0	0	14,755	0	14,755
D14LD22 East Lp 14kV Circuit Rblds Ph 2	0	0	590,658	25,079	615,737
D14LD23 WSpdway C-1 Recond Ph 3	0	0	289,393	0	289,393
D15LD48 Olive 13.8kV Conversion	0	0	0	389,096	389,096
SUBS109 Distribution Lines	6,579,615	8,068,074	6,343,671	1,190,796	22,182,156
D09BB02 Can Rnch 138kV Term for Duval Clr	478,476	1,048,526	685	0	1,527,687
D09BB04 Can Rnch - Duval Clr 138kV Line	4,055,501	1,806,320	-80,136	0	5,781,684
D09IQ02 Duval Clr 138kV Sub	1,133,101	4,881,405	5,896	47	6,020,448
D09LE24 Can Rnch - Duval Clr 138kV Line L&E	73,825	59,096	0	0	132,921
SUBS111 Duval Substation	5,740,902	7,795,347	-73,556	47	13,462,740
D07HN01 Harrison 138kV Sub - L&E	0	0	23,807	136,019	159,825
SUBS112 Harrison Substation	0	0	23,807	136,019	159,825
D07BB82 NL 138kV Terms for TO & RV	0	0	-22,911	0	-22,911
SUBS115 Trans Line - 138kV	0	0	-22,911	0	-22,911
D14BB82 Apache-Bicknell 230kV Ln Uprate	0	0	0	233,388	233,388
SUBS116 Trans Line - 345kV	0	0	0	233,388	233,388
CBONM00 46kV Line Repl & Betterments	-54,499	16,798	0	0	-37,701
CBORP00 Transmission Pole Refurbishments	298	113,557	115,133	6,545	235,533
D08LD53 Irv 46kV C-103 Reconductor	0	0	-6,985	0	-6,985
D09LD67 Technical-22nd St 46kV Rbld	11,723	0	-8,138	-7,290	-3,706
D10LD77 DMP C-2 Reconductor	18,335	0	0	0	18,335
D10LD78 22nd St-Brdwy 46kV Rbld & Reco	1,483,687	0	0	0	1,483,687
D10LD85 46kV GOAB Switch Installation	-6,967	0	0	0	-6,967
D10LD86 Brdwy-Spdwy Kolb 46kV Rebuild	0	232,237	1,223,302	0	1,455,539
D10LD87 Kolb-Wilmot ELp C-523 46kV Rbl	0	0	464,040	3,124,409	3,588,450
D10LD90 Irv C-109 & SLp C-544 600AMP T	1,092,580	0	0	0	1,092,580
D11LD01 SEECO 46kV Swtch Installs	267,731	335,714	278,645	6,294	888,384
D14LD27 46kV Crit Ckt Irv-111 & SOSU-542 Ph3	0	0	784,041	12,214	796,254
D14LD35 NE-607 46kV Rbld NE-Coronado Ph1	0	0	40,330	7,702	48,032
SUBS117 Trans Line - 46kV	2,812,887	698,306	2,890,366	3,149,874	9,551,434
CBOBZ00 Trans Subs Replc & Betts	483,130	1,232,576	1,279,583	537,911	3,533,200
CBONE00 Distribution Sub Replc/Bett	1,832,332	725,931	494,456	646,613	3,699,332
CBONS00 Dist Sub-Repc/Bett-Planned	-315	0	0	0	-315
D03BG01 Bushing Repl Var Subs	185,382	1,917,031	897,285	575,945	3,575,643
D09BL08 EHV 345kV Relay Upgrades	1,129,699	213,764	50,729	0	1,394,192
D09EO02 Wilmot T2 Replacement	0	60,321	2,436	1,858	64,615
D10BL10 138kV Breaker Replacements	0	150	-21	0	129
D10BL11 EHV Ckt Sw Rplcmnt SJ	-138,479	0	0	0	-138,479
D10BL12 EHV Ckt Sw Rplcmnt MC	231,302	0	0	0	231,302
D10BL13 EHV Ckt Sw Rplcmnt SP	41,783	942,612	-13,560	0	970,835
D10BL14 EHV Ckt Sw Rplcmnt WW	32,933	421,177	463,833	19,036	936,979
D10BL15 EHV Ckt Sw Rplcmnt SO	0	77,600	828,804	-34,856	871,548
D10BL16 EHV Bkr Rplcmnt MC-1	17,912	565,210	-15,934	0	567,188
D10BL17 EHV Bkr Rplcmnt MC-2	0	12,822	420,002	481,206	914,029
D10BL18 EHV Bkr Rplcmnt VL-1	59,545	0	0	0	59,545
D10DA03 East Loop T1 Replc	71,280	0	-22,798	0	48,482
D10DD92 NE T2 Replc	59,034	0	0	0	59,034
D11BB29 SP-RO 138kV Ln Relay Upgrade	-16,587	0	0	0	-16,587
D11BD04 McKinley 345kV Reactor Add	1,866,821	-8,778	0	0	1,858,043
D11DD93 NE T2A Swtchgr Replc	0	41,878	52,727	37,258	131,864
D11NM11 Cust Side Dist Connection	491,904	-211,830	12,274	0	292,347
D12BB30 EL-RO 138kV Ln Relay Upgd	454,452	175,330	0	0	629,782
D12BB31 DMP-S Cruz 138kV Ln Relay Upgd	4,400	410,358	773,581	0	1,188,340
D12BB46 FMI Sierrita Mine 138kV Metering	-538,149	524,370	14,013	-109	125
D12DP03 Country Club 46kV Sub Xfmr Rplc	0	10,779	5,440	0	16,219
D12DS03 Sparkman 46kV Sub Xfmr Rplc	0	0	164	0	164
D12IS03 Olive 46kV Sub Xfmr Rplc	0	0	169,980	2,037,673	2,207,653
D12LD13 NE T1 C610 46kV Relay Upgd	87,652	340,330	247,866	79,804	755,652
D12LD14 NL T1 C510 46kV Relay Upgd	35,923	69,746	-105,669	0	0
D12LD15 South Lp C542 46kV Relay Upgrade	1,135	59,033	0	0	60,168
D12LD16 South Lp C545 Relay Upgrade	0	65,596	188	0	65,784
D12LD17 South Lp C544 Relay Upgrade	0	52,115	148	0	52,263
D12LD18 Northeast C602 46kV Relay Upgrade	0	66,243	0	105,178	171,421
D12LD20 APC T3 Replacement	1,035,315	21,046	0	0	1,056,361
D13BB56 Ya-Ta-Hey □ Coalmine Metering Upgrd	0	46,659	51,525	-98,183	0
D13DA04 East Loop 138kV Cap Switcher Rplc	0	126,529	-941	0	125,588
D13DD94 NE 138kV Brkr Replc	2,094	1,008,034	-11,882	0	998,246
D13DD95 NE 46kV Brkr Replc	1,814	337,782	445,720	14,619	799,935
D13DF14 DMP 138kV Brkr Replc	0	10,679	346,264	23	356,967
D13DF15 DMP 46kV Brkr Replc	0	21,538	410,207	0	431,745
D13GB10 Wlna 138kV Brkr Replc (2)	0	252,211	405,158	743,879	1,401,249
D13GN12 NL 46kV Brkr Replc	0	378,782	538,580	38,185	955,548
D13GQ11 Rillito T1 Replacement	186,377	1,892,981	0	0	2,079,358

D13GQ12 Rillito 138kV Brkr Replc	104,223	491,835	26,434	0	622,492
D13HC03 Ft Huachuca 138kV Xfmr Rplc	0	0	6,850,668	988,101	7,838,768
D13IX09 Midvale 138kV Switch Replacements	0	425,044	-16,003	0	409,041
D13NM12 Grant T1 46kV Sub Xfmr Replc	0	354,711	1,935,919	0	2,290,630
D13SG36 West Ina T4 FSB	0	468,303	-201	0	468,102
D13SG37 Robert Bills T1 FSB	14,315	268,060	-1,213	0	281,161
D14BB70 Irv Sub 138kV Disc Swtch Rplc	0	0	112,040	0	112,040
D14NM13 25MVA Mobile Xfmr Relay Upgrade	0	0	158,759	181,522	340,281
D14NM15 Volt-Var Pilot Ph1 & 2	0	0	585,931	322,826	908,757
D15BG06 Spare Substation Equipment	0	0	0	1,516	1,516
D15DM03 TMC OCB 46 Brkr Rplc	0	0	13,586	394,178	407,765
D15GI08 Coronado 46kV Sub T2 Rplc	0	0	0	71,631	71,631
D15IO12 Vail 138kV Brkr Rplcs	0	0	0	35,059	35,059
D15NM19 TNI OCB 46 Brkr Rplc	0	0	0	5,077	5,077
D95EB06 Irv Sub Distribution Addition	-435	0	0	0	-435
SUBS118 Substation - R&B	7,736,792	13,868,560	17,406,078	7,185,951	46,197,380
D07FB01 Marana 138kV Sub - L&E	-5,302	0	0	0	-5,302
D07LE01 Marana Sub 138kV Ln Tap-L&E	-71,162	0	0	0	-71,162
SUBS119 Marana Substation	-76,465	0	0	0	-76,465
D07GO01 Orange Grove 138kV Sub - L&E	-7,418	0	2,764,832	587	2,758,001
SUBS121 Orange Grove Substation	-7,418	0	2,764,832	587	2,758,001
D07BL06 Pinal Central-Tortolita 500kV Line	1,123,183	1,519,921	3,192,556	42,495,031	48,330,691
D07LE08 Pinal Central-Tort 500kV Ln-L&E	1,123,358	644,711	4,611,912	1,283,764	7,663,744
D12BI11 Tort 500kV Yd Exp Ph 2 & Ln Term	0	0	658,063	4,788,151	5,446,213
SUBS122 Pinal Transmission Project	2,246,541	2,164,632	8,462,531	48,566,945	61,440,648
D08BB01 Rosemont Mine 138kV Line Tap	10,848	-10,848	0	0	0
D08LE23 Rosemont Mine 138kV Line Tap L&E	-17,731	0	0	0	-17,731
D09BB03 Toro 138kV Switchyard	-20,560	-2,952	0	0	-23,512
SUBS123 Rosemont Mine	-27,443	-13,800	0	0	-41,243
D15BB74 EHV Synchrophasor Program	0	0	0	99,535	99,535
D15NM17 Remote 46kV Switching	0	0	0	37,788	37,788
D15NM24 Distribution Automation	0	0	0	3,499	3,499
SUBS125 System Automation	0	0	0	140,822	140,822
D08BB71 NL-Wina 138kV Line Reconductor	0	0	556	5,013	5,569
D08BB88 NE 138kV Term Uprate for DMP	5,685	0	0	0	5,685
D10BB15 NL-DMP 138kV Ln 110 Uprate Ph1	-44	0	0	0	-44
D10BB19 DMP-NE 138kV Ln 127 Uprate Ph1	47,838	0	0	0	47,838
D13BB48 NL-Rillito 138kV Line Reconductor	0	0	1,182,981	128,166	1,311,147
D13BB49 NE-Rillito 138kV Ln Reconductor	0	0	1,525,181	58,632	1,583,813
D13BB53 NL-DMP 138kV Ln Reconductor	0	0	2,403,828	7,654,607	10,058,435
D13BB54 DMP-NE 138kV Ln Reconductor	0	1,763	2,382,913	1,317,879	3,702,555
D13BB55 Irv-Tuc 138kV Ln Uprate	0	6,709	0	0	6,709
SUBS128 Trans Lines - Uprate	53,480	8,472	7,495,459	9,164,297	16,721,707
D07LE07 DMP-Tucson 138kV Line - L&E	135,972	847,554	437,511	0	1,421,037
D08BB76 DMP-Tucson 138kV Ln	65,998	2,563,458	2,333,443	-105,794	4,857,105
D08BB77 DMP 138kV Term for Tucson	168,363	281,301	1,261,783	0	1,711,447
SUBS129 Trans Lines - DMP-Tucson	370,333	3,692,313	4,032,737	-105,794	7,989,589
D04BB32 Irv to 22nd St 138kV Ln Recon	639,688	-17,416	4,698	0	626,970
SUBS131 Trans Lines - Irvington to 22nd	639,688	-17,416	4,698	0	626,970
D08BB92 TO-NL 138kV Rebuild w SWTC	-194,752	0	-134,141	0	-328,893
D08LE21 TO-NL 138kV Rebuild w SWTC L&E	83,296	122	0	0	83,417
SUBS133 Trans Lines - Quad Circuit	-111,457	122	-134,141	0	-245,476
D10GN09 NL 138kV Yard Expansion Ph 2	890,099	3,217,192	-18,771	0	4,088,520
D10GN10 NL 138kV Yard Expansion Ph 3	0	2,670,417	2,208,323	0	4,878,740
SUBS134 North Loop Yard Expansion	890,099	5,887,609	2,189,553	0	8,967,260
D09DB03 Tucson Station Yard Exp	8,645	0	0	0	8,645
D10DB04 Tucson Station 46kV Relay Repl	768,605	677,638	0	0	1,446,243
D10DB05 Tucson Station Swtchgr Replc	8,796	2,141,692	1,750,939	0	3,901,427
SUBS135 Tucson Yard Expansion	786,046	2,819,330	1,750,939	0	5,356,315
D10BB22 Socorro 34.5kV Intertie - SPV	1,946	0	0	0	1,946
SUBS140 Socorro	1,946	0	0	0	1,946
D11BP05 Vail Series Cap Rplc-SP to Vail	18,092	2,927	5,467,811	1,967,448	7,456,278
D11BP06 Vail Series Cap Rplc-WIN to Vail	0	15,087	5,125,220	1,016,013	6,156,319
D11BT03 Greenlee Series Cap Rplc-SP to GL	0	0	21,118	3,965,927	3,987,045
SUBS141 EHV Series Caps	18,092	18,013	10,614,149	6,949,387	17,599,642
D10BI08 Tort 138kV B-Bus & Bay Bkr Rplc	1,000,133	1,956,886	-26,815	0	2,930,204
D11BI09 Tortolita Backup Station Service	4,042	16,820	527,458	48,922	597,242
D11BI10 Tort 138kV A-Bus Bkr Rplc	3,735,491	274,116	-3,010	0	4,006,597
D15BI12 Tort 500kV Brkr & Half Ph 3	0	0	804	4,822	5,625
SUBS142 Tortolita 138kV Yard Expansion	4,739,666	2,247,822	498,436	53,744	7,539,668
D05BL01 Palo Verde-Pinal West Part	19,224,465	576,794	73,342	0	19,874,601
D07BL04 PWest-SRosa Line & Sub Partcptn	7,001,765	19,191,063	2,131,204	-1,699,199	26,624,834
D08BI06 Tortolita 500kV Yrd Exp & T3 Adn	22,895	36,668	2,806	0	62,369

D13BL20 Pinal West Sta Serv Backup Gen	0	-11,765	869,962	-414,903	443,295
SUBS144 Pinal West Projects	26,249,126	19,792,761	3,077,314	-2,114,101	47,005,099
D10BN05 S Lp T2 Xfmr Replacement	-2,687,211	0	0	0	-2,687,211
SUBS145 South Loop Substation	-2,687,211	0	0	0	-2,687,211
D12DH02 UA-Hlth Sci Ctr 46kV GIS Intertie	-1,618,959	1,178,310	440,648	-528	-528
SUBS146 U of A Health Science Center Substation	-1,618,959	1,178,310	440,648	-528	-528
CBOESSR Dist E & S Sys Reinforcement	-758,606	803,694	130,626	-161,859	13,856
CBOTESR Tran E & S Sys Reinforcement	4,430	6,672	-11,102	15,018	15,018
SUBS147 E&S System Reinforcement	-754,176	810,366	119,525	-146,841	28,874
D15BL21 Torch Interconnection	0	0	-3,504,172	2,608,863	-895,310
D15BL22 PNM Yah-Ta-Hey Intercon #2	0	0	-1,625,145	1,267,928	-357,217
SUBS148 TEP Interconnections	0	0	-5,129,317	3,876,791	-1,252,527
D15IA01 AS&R Mission Mine Upgrades Ph1	0	0	1,911	321,228	323,139
SUBS149 Special Projects	0	0	1,911	321,228	323,139
CBOPC91 Electronics & Comm-Gen	-17,234	22,368	0	0	5,134
SUBS196 TEP Communication Gen	-17,234	22,368	0	0	5,134
CBOPC92 Electronics & Comm-Trans	3,238,913	2,779,917	1,018,948	-33,501	7,004,276
CBOTESC Trans E&S Communication	0	0	0	121,807	121,807
D13PC01 Irv-SPV MCW MDR Radio Upgd Ph 1	0	0	190,523	863,161	1,053,685
D13PC02 SRP Phx-Coronado MCW Path	0	0	2,202,486	340,767	2,543,253
D13PC04 P25 System Upgrade	0	0	6,356,180	1,669,137	8,025,317
D13PC06 TEP-APS Radio Interconnection	0	0	0	46,967	46,967
D13PC07 Irvington to Tucson Mtn MCW Upgrade	0	29,891	243,098	80,041	353,030
D14PC11 S Lp 138kV Hathaway SER to DIO Rplc	0	0	181,552	21,232	202,783
D14PC20 MCW Site Ethernet Ntwrk Addns Ph1	0	0	496,691	64,963	561,654
D14PC21 MCW Site Ethernet Ntwrk Addns Ph 2	0	0	158,157	696,577	854,733
D14PC22 MCW Site Ethernet Ntwrk Addns Ph 3	0	0	0	7,513	7,513
D14PC25 Weather Station Equip Upgrades Ph 1	0	0	868,442	0	868,442
D14PC26 Weather Station Equip Upgrades Ph 2	0	0	1,639	61,977	63,616
D14PC28 East Lp to Snyder MCW Upgrade	0	0	762,388	0	762,388
D14PC30 Roberts Sub CISCO 15454 Addition	0	0	78,612	227,357	305,969
D14PC34 Edgelink Mux to Fujisu Rplc	0	0	0	384,913	384,913
D14PC37 Fox-Deza MCW Upgrade	0	0	0	67,035	67,035
D14PC38 Irv-SPV MCW MDR Radio Upgd Ph 2	0	0	4,001	91,014	95,016
D14PC43 Springerville DACS	0	0	41,515	16,240	57,755
D14PC45 CIP Compliance RX1500 Install	0	0	56,329	2,275	58,604
D15PC41 Citywide Solar Irradiance Sensing	0	0	0	6,624	6,624
D15PC44 P25 System Upgd Ph2	0	0	0	967,925	967,925
SUBS197 TEP Communication Trans	3,238,913	2,809,808	12,660,561	5,704,022	24,413,303
CBODESC Dist E&S Communication	0	0	0	0	0
CBOPC93 Electronics & Commun-Dist	592,048	861,621	161,029	7,241	1,621,939
D14PC16 Alv Wy/L Rls Cooper Form 6 Comm	0	58,490	20,451	0	78,941
SUBS198 TEP Communication Dist	592,048	920,111	181,480	7,241	1,700,880
CBOBF00 Nav So Transm Sys Repl/Bett	1,034,772	30,282	-131,748	341,302	1,274,608
CBOBF03 ANPP Transm Sys Repl/Bett	1,868	42,821	58,478	68,873	172,040
CBOBF04 Four Corners Transm Sys Repl/Bett	328	15,540	36,942	172,777	225,587
CBOBF05 Hassayampa Pinal Central R&B	0	0	0	7,673	7,673
CBOMR00 Metering AMR Fixd Ntwrk Install	1,809,376	1,195,054	1,993,713	1,377,444	6,375,587
CBOOA02 Term Limited Land Rights Dist	0	0	106,264	4,100	110,364
CBOOA03 Term Limited Land Rights Tran	0	0	14,189	5,055	19,244
D03PB49 Backup Control Center	16,126	29,708	521,614	6,613	574,062
D04NM03 Subst Spill Prevention Mod	0	14,120	53,395	32,778	100,293
D05PJ35 Tie Open Load Shed Upgrade	330,735	221,491	-138	0	552,088
D07BB98 Irv Control Shelter Restoration	2,614	0	0	0	2,614
D08BG05 Fault Recorder Repl Various	17,506	0	0	0	17,506
D10PJ38 Vail EOC - Dual Porting	-4,422	0	0	0	-4,422
D13AE35 Volt Var Optimization Drexel	0	0	15,982	307	16,289
D151GAD Grid Advisor	0	0	0	186,594	186,594
D15BI13 Saguaro Replacement & Betterments	0	0	0	1,730,540	1,730,540
SUBS199 Misc - Tucson	3,206,903	1,549,016	2,668,690	3,934,056	11,360,665
SUBS100 TEP SR & Communication	68,662,437	74,963,826	78,551,894	88,339,675	310,517,833

Capital
UNS Consolidated
CC_UNS high level hierarchy
BC_UNS
Activity
FERC
Location
SubAccount
ET_A03 Directs Loads & Indirects

	2012 YearTotal Actual	2013 YearTotal Actual	2014 YearTotal Actual	2015 Jun YTD Actual	
ACCACRT Accruals-Unreleased APs TEP	7,394	(7,078)	1,744,138	(1,771,931)	
C080200 TEP Renewables	22,516,498	33,052,340	51,057,882	1,523,814	
A880310 Remote Stations	26,797,952	9,621,720	24,932,863	42,578,632	
A880320 Springerville Gen Station	18,218,831	39,096,606	55,513,140	2,509,366	
A880330 Tucson Power Production	10,770,252	29,638,191	17,535,550	5,576,652	
A880340 TEP New Resources	60,000	-	-	-	
C080300 TEP Prod	55,847,035	78,356,517	97,981,553	50,664,651	282,849,756
C080400 TEP General - Communication	3,813,727	3,752,287	12,842,040	5,711,263	26,119,317
C080500 TEP General - Facilities	8,094,616	6,028,247	8,234,873	1,423,161	23,780,897
C080600 TEP General - Info Tech	15,774,440	18,302,001	24,176,852	19,086,248	
C080700 TEP General - Other	164,507	1,587,551	730,059	175,239	2,657,356
C080800 TEP General - Fleet Equip	8,718,349	4,942,689	6,677,021	1,623,022	21,961,080
C080900 TEP Energy Delivery - New Business	16,929,624	14,811,847	21,708,711	14,822,923	68,273,105
C081000 TEP Energy Delivery - Public Improvement	7,338,559	8,771,654	6,032,724	4,341,445	26,484,382
A881101 TEP Dist Lines - New	5,245,304	3,453,482	1,887,787	79,010	10,465,583
A881102 TEP Dist Lines - Repl & Bettr	8,245,225	6,299,065	8,825,840	5,689,628	29,059,757
A881104 TEP Dist Subs - New	1,185,881	4,881,405	(10,389)	47	6,036,744
A881105 TEP Dist Subs - Repl & Bettr	5,819,094	7,434,838	12,773,578	5,893,563	31,920,573
A881106 TEP Dist Subs - Land & Environmtl	116,135	(2,999)	2,788,639	136,606	3,038,381
A881107 TEP Trans Lines - New	31,484,004	25,760,265	7,765,543	40,696,584	105,706,395
A881108 TEP Trans Lines - Repl & Bettr	438,231	7,854	6,565,241	10,685,529	17,696,855
A881109 TEP Trans Lines - Land & Envir	1,327,557	1,551,484	5,063,611	1,288,819	9,231,471
A881111 TEP Trans Subs - New	(1,639,519)	1,163,594	1,310,611	(349,617)	485,069
A881112 TEP Trans Subs - Repl & Bettr	13,401,047	19,852,687	18,803,888	18,654,778	70,712,400
CBOESSR Dist E & S Sys Reinforcement	(758,606)	803,694	130,626	(161,859)	
CBOTESR Tran E & S Sys Reinforcement	4,430	6,672	(11,102)	15,018	
D13AE35 Volt Var Optimization Drexel	-	-	15,982	307	
A882101 TEP SI Transmission	2,635,996	3,607,486	2,907,148	232,921	9,383,552
A882102 TEP SI Distribution	21,385,619	21,136,908	17,775,422	9,535,800	69,833,749
CBOESSI Dist E & S Sys Integ & Restore	15,143	(14,868)	(275)	(0)	
CBOTESI Tran E & S Sys Integ & Restore	(2,133)	2,437	(334)	(0)	
B080100 TEP Capital Projects	228,087,959	265,541,557	317,577,669	189,996,967	1,001,204,151
B080200 TEP Prelim Engineering	(1,206,942)	461,148	(164,121)	183,111	
A080000 TEP Capital & Prelim Eng	226,881,017	266,002,705	317,413,547	190,180,078	
	129,773,943				

Total Transmission	213
Total Distribution	245
	458
Communication	26
	484

Capital
UNS Consolidated
CC_UNS high level hierarchy
BC_UNS
Activity
FERC
Location
SubAccount
ET_403 Directs, Loads & Indirects

	2012 YearTotal Actual	2013 YearTotal Actual	2014 YearTotal Actual	2015 Jun YTD Actual			
ACCACRT Accruals-Unreleased APs TEP	7,394	(7,078)	1,744,136	(1,771,931)			
C080200 TEP Renewables	22,516,498	33,052,340	51,057,882	1,523,814			
A880310 Remote Stations	28,797,952	9,821,720	24,932,963	42,578,632			
A880320 Springerville Gen Station	18,218,831	39,096,606	65,513,140	2,509,366			
A880330 Tucson Power Production	10,770,252	29,638,191	17,535,550	5,578,852			
A880340 TEP New Resources	60,000	0	0	0			
C080300 TEP Prod	55,847,095	78,356,517	97,981,553	50,664,651			
C080400 TEP General - Communication	3,813,727	3,752,287	12,842,940	5,711,263	26,118,317	page 18	
C080500 TEP General - Facilities	8,094,818	8,028,247	8,234,873	1,423,181			
C080600 TEP General - Info Tech	15,774,440	18,302,001	24,178,852	19,086,246			
C080700 TEP General - Other	184,507	1,587,551	730,059	175,239			
C080800 TEP General - Fleet Equip	8,718,349	4,942,689	8,677,021	1,823,022			
C080900 TEP Energy Delivery - New Business	16,929,624	14,811,847	21,706,711	14,822,923	68,273,105	page 18	
C081000 TEP Energy Delivery - Public Improvement	7,338,559	8,771,654	6,032,724	4,341,445	26,484,382	page 18	
C081100 TEP Energy Delivery - Sys Reinforcement	64,848,584	71,211,539	65,709,854	82,628,412	284,398,390	295,783,992	page 18
C081200 TEP Energy Delivery - Sys Integrity & Restoration	24,034,626	24,731,963	20,881,962	9,768,721	79,217,271	371,081,263	page 18
B080100 TEP Capital Projects	228,087,959	265,541,557	317,577,669	189,996,957			
B080200 TEP Prelim Engineering	(1,206,942)	461,148	(164,121)	183,111			
A080000 TEP Capital & Prelim Eng	226,881,017	266,002,705	317,413,547	190,180,078	1,000,477,347		
					1,360,873,719		
T&D COMM, NB, PI, SI, SR	116,965,119	123,279,298	126,975,291	117,272,764	484,492,485		
Chris Norman's Numbers	130,168	117,143	126,444	117,594	491,349		
COMM, NB, PI, SI, SR WITH ADJUSTMENTS BELOW	128,351	123,279	126,575	117,273	495,878		
	page 18	page 18	page 18	page 18	page 18		
	1,817	(6,137)	(531)	321	(4,529)		

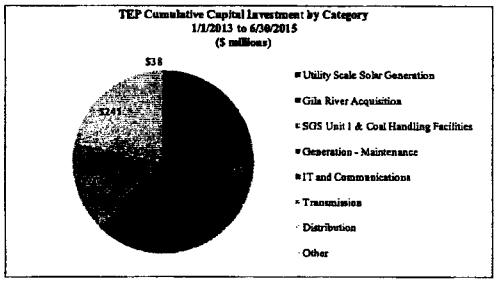
Utility Scale Solar Generation	$	108	Y	
Gila River Acquisition	$	164	163	
SGS Unit 1 & Coal Handling Facilities	$	162	151	$ 326 Gila & SGS page 18
Generation - Maintenance	$	283	Y	$ 283 Generation page 18
IT and Communications	$	103	Y	
Transmission	$	213	Y	
Distribution	$	245	Y	
Other	$	38	48	
	$	1,317		

SR & SI & Adjustments
Adjusted to tie back to C. Norman's numbers

		491		
		491		
		0		
per 10-K (net of CIAC):				
2012	2013	2014	YTD 2015	
243	249	491.1	334.3	$ 1,317
				page 18

ACT
Capital
Adjustments
Final
ET_000 Unspecified
CC_000 Unspecified

	2012 April	2012 July	2014 December	2015 January	2015 April	
D07BL04 PWest-SRoss Line & Sub Partcpin	11,385,602	0	0	0	0	
D05BL01 Palo Verde-Pinal West Part	0	(19,149,812)	0	0	0	
D14AF21 Gila River Purchase	0	0	162,701,396	0	0	
300161A Gila River Purchase	0	0	54,233,799	0	0	
D13SE06 SGS U1 Purchase	0	0	21,972,827	45,752,500	0	
D13SE07 SGS U1 Coal handling facility	0	0	0	0	83,299,960	360,196,372



2012

Capital
UNS Consolidated
CC_UNS high level hierarchy
BC_UNS
Activity
FERC
Location
SubAccount
ET_A03 Directs Loads & Indirects

	Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	Jul Actual	Aug Actual	Sep Actual	Oct Actual	Nov Actual	Dec Actual	Dec YTD Actual
D05SL01 Palo Verde-Pinal West Part	0	0	66,641	0	0	0	19,083,171	63,115	9,747	600	678	514	19,224,465
							19,149,812						

Run Date 5/27/15 8:13 AM

Capital
UNS Consolidated
CC_UNS high level hierarchy
BC_UNS
Activity
FERC
Location
SubAccount
ET_799 Transfers to Plant

	2005 Dec YTD Actual	2006 Dec YTD Actual	2007 Dec YTD Actual	2008 Dec YTD Actual	2009 Dec YTD Actual	2010 Dec YTD Actual	2011 Dec YTD Actual	2012 Dec YTD Actual	2013 Dec YTD Actual	2014 Dec YTD Actual	2015 Jun YTD Actual
D05BL01 Palo Verde-Pinal West Part	0	0	0	(15,696,224)	(25,997,554)	(10,237)	1,350,599	(19,149,812)	(638,227)	(73,342)	0

	14	51
		264%
		3.642857143

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BEFORE THE ARIZONA CORPORATION COMMISSION

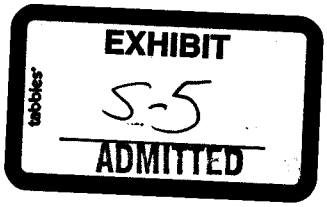
DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-01933A-15-0322

DIRECT
RATE DESIGN TESTIMONY
OF

MICHAEL J. MCGARRY, SR.
ON BEHALF OF THE
UTILITIES DIVISION STAFF
ARIZONA CORPORATION COMMISSION

JUNE 24, 2016



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TEP Proposal 2: PPFAC Allocation Change *6*

EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-15-0322

The Purchase Power and Fuel Adjustment Clause ("PPFAC") Rate Design Direct Testimony of Michael J. McGarry, Sr., of Blue Ridge Consulting Services, Inc. ("Blue Ridge"), provides Staff recommendations concerning two specific rate design proposals proffered by Tucson Electric Power Company ("TEP" or "Company") related to the Company's PPFAC. The first TEP proposed modification seeks to change the PPFAC adjustment to a twelve-month historical average versus the forward-looking methodology currently approved by the Commission. The second proposed modification targets change to the expression of the PPFAC adjustment from cents per kWh to a percentage of the base cost of fuel rate, included in base rates as approved by the Commission in this case.

Based on his analysis, Mr. McGarry finds that the Company has failed to show how these proposals benefit customers, and he believes that implementing the proposals might cause confusion and/or potential cross-subsidization. Staff recommends that the Arizona Corporation Commission ("Commission") reject both the Company's proposed changes to the PPFAC until TEP provides sufficient evidence that these proposals would indeed be beneficial to customers and would not cause confusion or any potential cross-subsidization. Specifically, Staff also recommends that the Commission (1) reject TEP's proposal to change from an annual determination of the PPFAC rate with its forward and true-up components to a twelve-month historical rolling average, and (2) reject TEP's proposal to alter the expression of the PPFAC adjustment to a percentage change of the base cost of fuel rate from the current expression as cents per kWh appearing on customer bills (which is consistent with Staff's position in the UNS Electric, Inc. ("UNS") case, Docket No. E-04204A-15-0142).

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Michael J. McGarry, Sr. I am Senior Technical Consultant with Blue Ridge Consulting Services, Inc. My business address is 114 Knights Ridge Road, Travelers Rest, South Carolina 29690.

BACKGROUND AND QUALIFICATIONS

Q. Are you the same Michael J. McGarry Sr. that proffered testimony in the revenue requirements portion of this case?

A. Yes. My testimony was filed with the Commission on June 3, 2016.

Q. Are your background and qualifications the same here as offered in that filing?

A. Yes. Exhibit MJM-1 attached to that submission is applicable here as well.

Q. Just to reiterate, have you previously testified before the Arizona Corporation Commission ("Commission")?

A. Yes. I have testified in Docket Nos. E-01345A-11-0224, E-04204A-12-0504, and E-01933A-12-0291.

PURPOSE OF TESTIMONY

Q. On whose behalf are you testifying?

A. I am appearing on behalf of the Commission Utilities Division Staff ("Staff").

Q. What is the purpose of the testimony you are presenting?

A. I present the Staff's position with respect to the proposals of Tucson Electric Power Company ("TEP" or "Company") concerning modification of the Purchase Power and Fuel Adjustment Clause ("PPFAC").

Q. Was this testimony and the supporting analyses prepared by you or under your direct supervision?

A. Yes.

Q. Please briefly describe the information you reviewed in preparation for your testimony.

A. I have reviewed the Company's testimony, exhibits, and data request responses provided by the Company to the various parties to this proceeding.

CONTENT OF ATTACHMENTS TO TESTIMONY

Q. Have you attached any exhibits to your testimony?

A. No.

PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE

Q. Is the Company proposing any changes to the PPFAC?

A. Yes. TEP is requesting a major modification to the PPFAC to (1) implement a monthly change in the rate (which is currently recalculated only annually) and (2) allocate these monthly adjustments to the PPFAC costs on the same percentage basis to all rate classes. As Company Witness Jones states, "The PPFAC charge will be a single percentage adjustment

applied to all base rates for all customer classes."[1] In addition, Company Witness Sheehan discusses the Company's proposed change to make the PPFAC a rolling average.

Q. Please briefly explain the PPFAC's current structure in regard to the elements for which modification is proposed.

A. The Company's current PPFAC includes a component called the *base cost of fuel rate* that is established in a base rate case and, therefore, will be set in this case. This *base cost of fuel rate* is fixed until changed by approval of the Commission in a subsequent base rate case.

The current PPFAC also includes two components that are established outside a base rate case: the *forward component* and the *true-up component.* The *forward component* is set annually in a PPFAC filing made by the Company and as ordered by the Commission. The last PPFAC filed by TEP was February 1, 2016. This *forward component* is a projection of fuel and purchased power costs for the upcoming 12-month period, during which the forward component is expected to be in effect. It is calculated using a sophisticated production-modeling program called AuroraXMP.

The *true-up component* is, as its designation suggests, the difference between the previous 12-month *forecast component* and the *actual* purchased power and fuel costs the Company incurred during that previous 12-month period.

Through this PPFAC structure that has been in place, the Company is currently allowed to recover the following purchased power and fuel-related costs from customers:

[1] Direct Testimony of Craig A. Jones at page 77, lines 3-8.

Component	Authorized Recovery (¢ per kWh)[2]
Base Cost of Fuel	3.2335
Forward Component	0.2782
True-up	(0.1281)
Average Total Rate	3.3836

TEP Proposal 1: PPFAC Frequency Change

Q. Please explain the details of the Company's proposal.

A. As mentioned, the first of the Company's PPFAC proposals is to alter the frequency by which the PPFAC rate is changed. The frequency change is from annually to monthly. This change would remove the forward component's 12-month projection of costs in favor of calculating a historical 12-month rolling average. Company Witness Sheehan states in his testimony,

> TEP is proposing to modify its PPFAC to consist of a base rate and a PPFAC percentage rate. The sum of the base rate and the PPFAC percentage rate will be derived by using the prior twelve month's weighted average fuel costs, net of short-term wholesale revenues. Each month the calculation will fluctuate based upon actual net costs of the prior 12-monthly period.[3]

Witness Sheehan then states that the base rate of fuel costs will remain fixed and only the PPFAC percentage will change each month.

Q. Does the Company provide justification for this change?

A. In my view, the Company offers only limited and insufficient justification for this major change. The Company states that the reason for the proposed change is to smooth the volatility of fuel costs for customers.[4] Witness Sheehan notes that this type of rolling average

[2] TEP PPFAC filing dated February 1, 2016. Approved by Commission Order dated April 22, 2016. Rates effective May 1, 2016.
[3] Direct Testimony of Michael Sheehan – page 42, Lines 8-13.
[4] Ibid. at page 42, lines 25-26.

is utilized in TEP's sister companies, UNS Electric and UNS Gas. He also notes that TEP is moving toward a more natural gas-based generation mix and away from coal, costs of which have traditionally been very stable. He states as justification that the annual reset of PPFAC rate has created a couple of instances of "significant bill impact."[5] Witness Sheehan proposes that the transition to the twelve-month rolling average combined with effective hedging will lower PPFAC volatility and smooth potential bill impacts.[6]

Q. Does the Company provide recast comparison of previous fuel costs to show what the impact of its proposal would have been during the test year (or any other period)?

A. No. The Company provides no additional analysis or comparisons whatsoever. It merely states without substantiation that volatility will decrease.

Q. Are there any other factors to consider in the frequency change?

A. Yes. The current 12-month projection may anticipate expected changes that may not be part of the historical trend. Therefore, if the PPFAC rate ignores any forecast and takes into account only historical trend, volatility may still be a factor. This is particularly true if the Commission were to adopt the 12 month rolling average as proposed. Customers would be used to a single rate change each April/May and now that change is monthly. This potentially could cause customer to question why rates are changing frequently.

Q. What is your opinion of the Company's proposal to go from an annual rate to monthly rolling average?

A. The Company has not satisfactorily demonstrated its presumed reduction of volatility, and potential unintended consequences of changing the methodology on customers. There is insufficient analysis to determine whether moving to a monthly rolling average would be

[5] Direct testimony of Michael Sheehan at page 43, lines 1-3
[6] Ibid at lines 3-5

beneficial to customers or create additional confusion. Therefore, until the Company can demonstrate its claims regarding volatility reduction with the proposed change and impacts on customers, it is my opinion that the Commission should reject the Company's proposal.

TEP Proposal 2: PPFAC Allocation Change

Q. Please describe the Company's other proposed PPFAC change to allocation of PPFAC rate from an incremental increase/decrease in cents per kWh to a percentage-based increase/decrease to each customer class?

A. As I mentioned previously, the Company intends to modify the allocation of the increase or decrease to the monthly recalculated PPFAC rate from cents per kWh to a single percentage basis across all customer classes. Company Witness Jones provides one short statement explaining the Company's position.[7] As an example, if the PPFAC were calculated resulting in a 0.5 percent increase, compared to the existing cost of fuel base rate approved in this case, then each customer class (i.e., residential, small commercial, and LPS) would see the same 0.5 percent adjustment as a PPFAC adder.[8] As explained earlier, the PPFAC adder is currently calculated on a cents per kWh basis and then added to the customer's bill. Witness Jones states that the percentage method "better aligns the changes in fuel costs with each rate class' base fuel costs."[9]

Q. Beyond the Company's testimony, was there any analysis provided that supported the Company's claim or showed how customers would benefit from the proposed rate design allocation change?

A. No. The Company's statement was left unsubstantiated

[7] Direct Testimony of Craig Jones at page 77, lines 10-18.
[8] Ibid at lines 17-18
[9] Ibid at line 12-13

Q. Do you have an opinion concerning this proposal?

A. Yes. Consistent with Staff's position in the UNS case, Docket No. E-04204A-15-0142, I recommend that the PPFAC remain as a calculation of cents per kWh. There is no evidence to suggest that customers would benefit from changing to the Company's proposed plan.

Q. Please summarize Staff's rate design recommendations for the PPFAC?

A. Staff recommends that the Commission reject the Company's proposed changes to PPFAC until such time that the Company provides sufficient evidence that these proposals would be beneficial to customers and not cause confusion or any potential cross-subsidization. Specifically, Staff recommends that the Commission reject the Company's proposal:

- To move from an annual determination of the PPFAC rate, with its forward and true-up components, to a twelve-month historical rolling average, and
- To change how these monthly adjustments to the PPFAC are expressed from a cents per kWh basis on customer bills to a percentage change that would be applied equally to all customer classes.

Q. Does this conclude your PPFAC Rate Design Testimony?

A. Yes. It does.

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239

SURREBUTTAL

TESTIMONY

OF

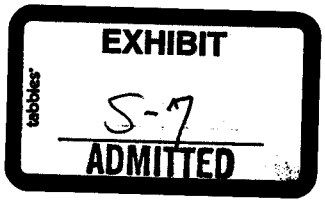
MICHAEL J. MCGARRY SR.

FOR THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 26, 2016



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EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NOS. E-01933A-15-0239 AND E-01933A-15-0322

Mr. McGarry's surrebuttal testimony reviews the Tucson Electric Power Company ("TEP" or "Company") rebuttal testimony with respect to a Company concession made in rebuttal, and recommends rejection of the Company's continued position related to the Purchased Power and Fuel Adjustor Clause.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Michael J. McGarry Sr. I am a Senior Technical Consultant with Blue Ridge Consulting Services, Inc. ("Blue Ridge"). My business address is 114 Knightsridge Rd., Travelers Rest, SC 29690.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Arizona Corporation Commission ("Commission") Utilities Division Staff ("Staff").

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I have submitted testimony in this proceeding.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony addresses Tucson Electric Power Company's ("TEP" or "Company") rebuttal testimony concerning my direct testimony related to the Purchased Power and Fuel Adjustment Clause ("PPFAC").

Q. Please summarize Staff's position with regard to the PPFAC introduced in your prior testimony in this case.

A. With respect to rate design, in my testimony submitted on June 24, 2016, I recommended that the Commission reject both the Company's proposed changes to the PPFAC: (1) to change from an annual determination of the PPFAC rate with its forward and true-up components to a twelve-month historical rolling average and (2) to alter the expression of the PPFAC adjustment to a percentage change of the base cost of fuel rate from the current expression as cents per kWh appearing on customer bills.

SURREBUTTAL TESTIMONY

Q. What is the focus for your surrebuttal testimony?

A. I will address my acknowledgement of a Company concession made in rebuttal; and my recommendation for rejection of the Company's continued position related to the PPFAC and that it be calculated using a 12-month historical average.

CONCESSION

Q. Please discuss the concession the Company made in rebuttal.

A. With respect to the Company's proposal to modify the way the PPFAC is applied to the rate classes to be based on a percentage increase, the Company withdrew that proposal in rebuttal.[1]

PPFAC BASED ON HISTORICAL 12-MONTH ROLLING-AVERAGE COSTS

Q. What is the Company's rebuttal position with respect to the PPFAC?

A. In his rebuttal testimony, Witness Robey continues to request that the Commission approve the Company's proposal to calculate the PPFAC using a 12-month average of historical/actual costs.[2] He maintains that the Company believes there are significant benefits that would arise out of using this methodology.[3]

Q. Please summarize the Company's proposal in direct testimony.

A. As I noted in my direct testimony at page 4, TEP is proposing to modify its PPFAC to consist of a base rate and a PPFAC percentage rate. The sum of the base rate and the PPFAC percentage rate would be derived by using the prior twelve month's weighted average fuel costs, net of short-term wholesale revenues. Each month the calculation would fluctuate

[1] Rebuttal testimony of Ramondo J. Robey at page 2, line 23.
[2] Rebuttal testimony of Ramondo J. Robey at page 2, lines 24-25
[3] Ibid.

based upon actual net costs of the prior 12-month period and would be banded by a 1 percent collar; that is, the change in the adjustable portion of the PPFAC would be limited to no more than + /- 1 percent from one month to the next.[4]

Q. What does the Company regard as the "significant benefits" that would result from their proposed new methodology?

A. Witness Robey proffers that there are two benefits: (1) the 12-month rolling-average would improve the predictability of anticipated PPFAC charges by eliminating the Forward Component and True-Up Component used in the current PPFAC rate in favor of using actual historical costs and (2) limiting the potential change from month to month by 1 percent would reduce the potential for significant bill impacts with annual adjustment of the PPFAC rate as currently in place.[5]

Q. Do you agree with Witness Robey?

A. As it applies to TEP's situation, not entirely, and therefore, I continue to recommend that the Commission reject the Company's proposal.

Q. Please explain why you disagree with the Company's proposal.

A. As stated in my direct, the Company has not provided sufficient justification for making such a significant change. Its use by other companies does not in itself provide proof that it would benefit TEP's customers. In addition, the Company argues that administering another monthly adjustment clause would not "create challenges for Staff."[6] In either case, the Company has not provided any evidence to show what would have happened with a rolling average calculation and how the PPFAC would have changed month to month. Further, they

[4] Rebuttal Testimony of Ramondo J. Robey at page 3, lines 13-15.
[5] Rebuttal Testimony of Ramondo J. Robey at page 3, lines 3-16.
[6] Rebuttal Testimony of Ramondo J. Robey at page 5, lines 20-22

offer no evidence that customers prefer or at the very least are not adverse to a monthly change. Witness Robey simply states that to his knowledge, "there have been no complaints regarding bill complexity."[7] While acknowledging large increases in a customer's bill can generate concern from customers, my position is that frequent changes (i.e., monthly increases) can also generate customer concern. The Company did not provide evidence (i.e., number of complaints related to change in the PPFAC) even though Witness Robey states that there were complaints. Simply stating that it happens is not justification for such a major change. Therefore, and in consultation with Staff who would be required to administer the monthly PPFAC, I continue to recommend that the Commission reject the Company's proposed monthly adjustment based on historical 12-month average costs in favor of maintaining the current methodology (i.e., true-up and adjust annually based on a forward-looking component).

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

[7] Rebuttal testimony of Ramondo J. Robey at Page 5, line 7

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
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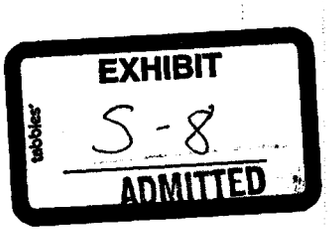
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-01933A-15-0322

DIRECT TESTIMONY OF ROXIE MCCULLAR ON BEHALF OF THE UTILITIES DIVISION STAFF ARIZONA CORPORATION COMMISSION

JUNE 3, 2016



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APPENDIX

Background and Experience Profile for Roxie McCullar, C.P.A. ..... Appendix A

EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-15-0322

Roxie McCullar's direct testimony addresses the depreciation rates filed by Tucson Electric Power Company ("TEP" or "Company") in this proceeding.

Ms. McCullar recommends that the Staff proposed depreciation rates shown on Schedule RMM-1 be approved for TEP in Arizona. The Staff proposed depreciation rates shown on Schedule RMM-1 include the following adjustments to TEP's proposed depreciation rates:

(1) A -5 percent future net salvage percent for Distribution Plant. This -5 percent future net salvage percent is supported by the actual historic net salvage percent which has averaged -4.4 percent over the last 25 years;

(2) A final retirement year of 2032 for Sundt Steam Units 1 and 2, North Loop CT Units 1, 2, and 3, and Sundt CT Units 1 and 2, which is supported by the Company's future plans for providing electric service as shown in its 2016 IRP; and

(3) The estimated dismantlement costs be set at current dollars, instead of TEP's proposal to estimate future inflated dismantlement costs in lower value future dollars and, based on that inflated future cost, to collect from current ratepayers in the more valuable current dollars.

Comparison of Proposed Depreciation Rates

		TEP Proposed			Staff Proposed			
Function	12/31/14 Investment	Investment	Net Salvage	Total	Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Steam Production	1,775,183,769	3.09%	0.55%	3.65%	2.99%	0.36%	3.35%	-0.29%
Other Production	550,310,918	2.68%	0.21%	2.89%	2.65%	0.14%	2.79%	-0.11%
Distribution	1,393,613,489	1.80%	0.25%	2.05%	1.69%	0.08%	1.77%	-0.28%
General Plant	329,266,089	6.01%	-0.13%	5.89%	6.01%	-0.13%	5.89%	0.00%
Total	4,048,374,265	2.83%	0.35%	3.18%	2.74%	0.20%	2.94%	-0.24%

Comparison of 2015 Annualized Accrual Based on 12/31/14 Investments

		TEP Proposed			Staff Proposed			
Function	12/31/14 Investment	Investment	Net Salvage	Total	Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Steam Production	1,775,183,769	54,889,358	9,841,101	64,730,459	53,058,969	6,441,962	59,500,931	(5,229,528)
Other Production	550,310,918	14,752,043	1,173,557	15,925,600	14,578,777	762,976	15,341,753	(583,847)
Distribution	1,393,613,489	25,101,719	3,484,034	28,585,753	23,581,622	1,114,891	24,696,512	(3,889,241)
General Plant	329,266,089	19,798,821	(415,264)	19,383,557	19,798,821	(415,264)	19,383,557	0
Total	4,048,374,265	114,541,941	14,083,428	128,625,369	111,018,189	7,904,564	118,922,753	(9,702,616)

INTRODUCTION

Q. Please state your name and business address?

A. My name is Roxie McCullar. My business address is 8625 Farmington Cemetery Road, Pleasant Plains, Illinois 62677.

Q. What is your present occupation?

A. Since 1997, I have been employed as a consultant with the firm of William Dunkel and Associates and have regularly provided consulting services in regulatory proceedings throughout the country.

Q. Please describe your educational and professional background.

A. I am a Certified Public Accountant licensed in the state of Illinois. I received my Master of Arts degree in Accounting from the University of Illinois in Springfield. I received my Bachelor of Science degree in Mathematics from Illinois State University in Normal. Over the past 18 years I have filed testimony in over 40 state regulatory proceedings on cost allocation, universal service, and depreciation issues.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Arizona Corporation Commission Utilities Division Staff ("Staff").

Q. Have you prepared an appendix that describes your qualifications?

A. Yes. My qualifications and previous experiences are shown on the attached Appendix A.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the depreciation rates filed by Tucson Electric Power Company ("TEP" or "Company") in this proceeding.

SUMMARY

Q. Can you summarize your recommendations?

A. Yes. I recommend that the Staff-proposed depreciation rates shown on Schedule RMM-1 be approved for TEP in Arizona.

The Staff-proposed depreciation rates shown on Schedule RMM-1 include the following adjustments to TEP's proposed depreciation rates:

(1) I recommend a -5 percent future net salvage percent for Distribution Plant. This -5 percent future net salvage percent is supported by the actual historic net salvage percent which has averaged -4.4 percent over the last 25 years;

(2) I recommend a final retirement year of 2032 for Sundt Steam Units 1 and 2; North Loop CT Units 1, 2, and 3; and Sundt CT Units 1 and 2, which is supported by the Company's future plans for providing electric service as shown in its 2016 IRP; and

(3) I recommend that the estimated dismantlement costs be set at current dollars, instead of TEP's proposal to estimate future inflated dismantlement costs in lower value future dollars and, based on that inflated future cost, to collect from current ratepayers in the more valuable current dollars.

Q. Can you summarize the Staff-recommended depreciation rates?

A. Yes. The Staff recommended-depreciation rates compared to the TEP-proposed depreciation rates are summarized below:

Table 1:

Comparison of Proposed Depreciation Rates

		TEP-Proposed			Staff-Proposed			
Function	12/31/14 Investment	Investment	Net Salvage	Total	Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Steam Production	1,775,183,769	3.09%	0.55%	3.65%	2.99%	0.36%	3.35%	-0.29%
Other Production	550,310,918	2.68%	0.21%	2.89%	2.65%	0.14%	2.79%	-0.11%
Distribution	1,393,613,489	1.80%	0.25%	2.05%	1.69%	0.08%	1.77%	-0.28%
General Plant	329,266,089	6.01%	-0.13%	5.89%	6.01%	-0.13%	5.89%	0.00%
Total	4,048,374,265	2.83%	0.35%	3.18%	2.74%	0.20%	2.94%	-0.24%

The 2015 annualized accrual based on December 31, 2014, investments using Staff-recommended depreciation rates compared to the TEP-proposed depreciation rates are summarized below:[1]

Table 2:

Comparison of 2015 Annualized Accrual Based on 12/31/14 Investments

		TEP-Proposed			Staff-Proposed			
Function	12/31/14 Investment	Investment	Net Salvage	Total	Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Steam Production	1,775,183,769	54,889,358	9,841,101	64,730,459	53,058,969	6,441,962	59,500,931	(5,229,528)
Other Production	550,310,918	14,752,043	1,173,557	15,925,600	14,578,777	762,976	15,341,753	(583,847)
Distribution	1,393,613,489	25,101,719	3,484,034	28,585,753	23,581,622	1,114,891	24,696,512	(3,889,241)
General Plant	329,266,089	19,798,821	(415,264)	19,383,557	19,798,821	(415,264)	19,383,557	0
Total	4,048,374,265	114,541,941	14,083,428	128,625,369	111,018,189	7,904,564	118,922,753	(9,702,616)

[1] Schedule RMM-1 shows the annual accruals based on the 12/31/14 investment levels. However, in the future as the investments change, the depreciation rates will be applied to the then current investments, which will produce a different annual accrual amount.

DISTRIBUTION PLANT NET SALVAGE

Q. Do you have a recommendation regarding TEP's proposed future net salvage percent for Distribution Plant?

A. Yes. Based on TEP's actual experience, I recommend a -5 percent future net salvage percent for Distribution Plant, which results in a 0.08 percent annual depreciation rate and collects $1.1 million per year for net salvage for Distribution Plant.[2]

Q. Please explain what is meant by net salvage.

A. In the Arizona Administrative Code, Net Salvage is defined as "the salvage value of property retired less the cost of removal."[3] Salvage Value is defined as "the amount received for assets retired, less any expenses incurred in selling or preparing the assets for sale; or if retained, the amount at which the material recoverable is chargeable to materials and supplies, or other appropriate accounts."[4] Cost of Removal is defined as "the cost of demolishing, dismantling, removing, tearing down, or abandoning of physical assets, including the cost of transportation and handling incidental thereto."[5]

Q. What impact does net salvage have on depreciation rates?

A. Positive net salvage results in a lower depreciation rate, everything else equal. Negative net salvage results in a higher depreciation rate, everything else equal.

As stated in National Association of Regulatory Commissioners' ("NARUC's") Public Utilities Depreciation Practices publication:

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[2] See Schedule RMM-1.
[3] Arizona Administrative Code R14-2-102.
[4] Arizona Administrative Code R14-2-102.
[5] Arizona Administrative Code R14-2-102.

> "Positive net salvage occurs when gross salvage exceeds cost of retirement, and negative net salvage occurs when cost of retirement exceeds gross salvage."[6]

Q. What negative net salvage percent is TEP proposing for Distribution Plant?

A. TEP is proposing a -15 percent future net salvage percent for Distribution Plant, which results in a 0.25 percent annual depreciation rate and collects $3.4 million per year for negative net salvage for Distribution Plant.[7]

Q. What information did TEP provide supporting its proposed -15 percent future net salvage percent for Distribution Plant?

A. TEP's 2015 Depreciation Rate Study states:

> "Estimates of net salvage rates applicable to future retirements are most often derived from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a basis for estimating future salvage and cost of removal. However, consideration should be given to events that may cause deviations from net salvage realized in the past. Factors that should be considered include: the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to net salvage rates observed in the past."[8]

The Depreciation Rate Study does include "an analysis of gross salvage and cost of removal realized in the past." As stated in Dr. White's testimony:

> "Q. DID FOSTER ASSOCIATES CONDUCT A NET SALVAGE ANALYSIS IN THE 2015 STUDY?

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[6] Page 18, Public Utilities Depreciation Practices, published by National Association of Regulatory Commissioners (NARUC), 1996.
[7] Exhibit REW-1, pages 18, 28, and 81.
[8] Exhibit REW-1, page 10.

> A. Yes. Five-year moving averages of the ratio of realized salvage and cost of removal to the associated retirements were used in the study for distribution and general plant categories to a) estimate realized net salvage rates; b) detect the emergence of historical trends; and c) establish a basis for estimating future net salvage rates. Cost of removal and salvage opinions obtained from TEP operating personnel were blended with judgment and historical net salvage indications in developing estimates of the future"[9]

Q. Did Dr. White receive any information from TEP that indicates the future Distribution Plant net salvage will be significantly different than the recent historical trend?

A. No. In response to discovery, TEP stated:

> "Dr. White neither observed nor was informed of any significant changes in the composition of plant categories or anticipated changes in future forces of retirement that would measurably impact hazard rates or conditional probabilities of retirement observed in the past."[10]

Q. What is Schedule RMM-2?

A. Schedule RMM-2 is TEP's response to the discovery request quoted above.

Q. What does the Distribution Plant historical net salvage analysis in the 2015 Depreciation Rate Study indicate about the "gross salvage and cost of removal realized in the past" and the "historical trends"?

A. Attached as Schedule RMM-3 is page 110 of TEP Exhibit REW-1 which shows the actual historical net salvage of Distribution Plant for the last 25 years. This analysis shows that overall the historical net salvage has averaged -4.4 percent over the last 25 years.

This analysis also shows that the actual net salvage has been positive since 2008.

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[9] White Testimony page 8, lines 3-11
[10] TEP response to RUCO 1.02, attached as Schedule RMM-2.

My recommended -5 percent future net salvage percent is closer to the actual experience than TEP's -15 percent proposed future net salvage percent.

Q. Does the recent trend support a more positive net salvage percent?

A. Yes. In recent years, the net salvage for Distribution Plant has been positive. This means that TEP has received enough gross salvage to cover the cost of retiring and did not need to collect any cost of removal expense from ratepayers. Table 3 below shows the actual net salvage history for the last five years.

Table 3:

Distribution Plant Net Salvage History Last Five Years					
Year	Retirements	Gross Salvage	Cost of Retiring	Net Salvage	Percent
A	B	C	D	E=C-D	F=E/B
2010	$6,741,625	$1,899,492	$1,491,496	$407,996	6.1%
2011	9,584,974	3,886,122	1,954,166	1,931,956	20.2%
2012	9,894,066	3,483,875	1,981,445	1,502,430	15.2%
2013	10,388,388	3,167,575	1,645,569	1,522,006	14.7%
2014	18,904,562	3,364,056	1,693,337	1,670,719	8.8%
Last Five Years	$55,513,615	$15,801,119	$8,766,012	$7,035,107	+12.7%

Since the net salvage has been positive in recent years, as shown above, my recommended -5 percent future net salvage percent is conservative.

Q. Please summarize your recommendation for net salvage for Distribution Plant.

A. I recommend a -5 percent future net salvage percent for Distribution Plant. This -5 percent future net salvage percent is supported by the historic net salvage analysis which has averaged -4.4 percent over the last 25 years.

PRODUCTION PLANT YEAR OF FINAL RETIREMENT

Q. Do you have a recommendation regarding TEP's proposed year of final retirement for Production Plant?

A. Yes. The Company's 2016 Integrated Resource Plan ("IRP")[11] shows that Sundt Steam Units 1 and 2; North Loop CT Units 1, 2, and 3; and Sundt CT Units 1 and 2 are expected to be providing service at least through 2032.

I recommend extending the final retirement year for these units to 2032.

Q. Does TEP recommend an extension of the final retirement year for these production units?

A. Yes. TEP recognizes that several units are now expected to retire later than assumed in the prior Depreciation Rate Study. However, the retirement dates used in TEP's Depreciation Rate Study filed in this proceeding are still earlier than the retirement dates used in TEP's 2016 IRP.

As stated in TEP Witness Michael E. Sheehan's Direct Testimony:

> "Q. What is the Company's recommendation on the retirement dates for the Sundt and North Loop generating resources?
> A. The Company is recommending extending the retirement dates on all of the local area units[36] by ten years. The Company has chosen a ten-year timeframe in order to properly determine the long-term viability of these older natural gas generation resources in the context of TEP's future resource planning environment."
>
> Footnote 36: "North Loop Unit 4 and Sundt Unit 4 are excluded from this recommendation since these units currently have retirement dates of 2046 and 2048 respectively."[12]

[11] TEP's "most recent Integrated Resource Plan" provided in response to UDR 1.006 which included a link to "Tucson Electric Power March 1, 2016 Preliminary Integrated Resource Plan". See Schedule RMM-4.
[12] Page 27, line 25 – page 28, line 3 of Sheehan Direct Testimony.

The Company is recommending a 10-year extension of the final retirement year for Sundt Steam Units 1, 2, and 3; North Loop CT Units 1, 2, and 3; and Sundt CT Units 1 and 2. Table 4 below shows the current approved year of final retirement ("YFR"), TEP's proposed year of final retirement, and the year these units are assumed to be in service in TEP's 2016 IRP.

Table 4:

Production Plant Units Life Span Increases in 2016 IRP

Plant	Unit	In Service[13]	Current Approved YFR[14]	Current Approved Life Span	TEP Proposed YFR[15]	TEP Proposed Life Span	TEP Proposed Difference from Current[16]	2016 IRP Retirement Year of at Least 2032[17]	Minimum Life Span in 2016 IRP	Difference from TEP Proposed
A	B	C	D	E=D-C	F	G=F-C	H=G-E	I	J=I-C	K=J-H
Steam Production										
Sundt	1	1958	2018	60	2028	70	10	2032 or later	74 or longer	4
Sundt	2	1960	2020	60	2030	70	10	2032 or later	72 or longer	2
Sundt	3	1962	2022	60	2032	70	10	2032 or later	70 or longer	0
Other Production										
North Loop CT	1-3	1972	2017	45	2027	55	10	2032 or later	60 or longer	5
Sundt CT	1-2	1972	2017	45	2027	55	10	2032 or later	60 or longer	5

TEP's extension of 10 years for these units in the Depreciation Rate Study moves the year of final retirement closer to the in service year of 2032 or later assumed for these units in the 2016 IRP, but does not go as far as the retirement dates assumed in the 2016 IRP.

As shown in the last column of Table 4 above, the 2016 IRP assumes Sundt Steam Units 1 and 2; North Loop CT Units 1, 2, and 3; and Sundt CT Units 1 and 2 will be in service several years after the proposed year of final retirement used in TEP's Depreciation Rate Study.

[13] Page 2 of Sheehan Direct Testimony.
[14] Exhibit REW-1, Statement H
[15] Exhibit REW-1, Statement H
[16] Page 27, line 25 – page 28, line 3 of Sheehan Direct Testimony.
[17] TEP's "most recent Integrated Resource Plan" provided in response to UDR 1.006 which included a link to "Tucson Electric Power March 1, 2016 2016 Preliminary Integrated Resource Plan".

Q. What is Schedule RMM-4?

A. Schedule RMM-4 is the page from the Company's 2016 IRP which shows these units are assumed to be in service until at least 2032.

Q. What do you recommend on this issue?

A. I recommend that the final retirement year of 2032 be used for Sundt Steam Units 1 and 2; North Loop CT Units 1, 2, and 3; and Sundt CT Units 1 and 2, as supported by the Company's future plans for providing electric service in its 2016 IRP.

INFLATION OF PRODUCTION PLANT DISMANTLEMENT COSTS

Q. Do you have a recommendation regarding the amount of dismantlement costs included in TEP's proposed depreciation rates?

A. Yes. TEP is inflating the dismantlement costs to the year of final retirement but collecting the future inflated estimated costs in today's more valuable dollars. TEP's proposal collects the more valuable current dollars to pay for estimated future inflated dismantlement costs.

For example, the company-provided engineering study estimates Sundt Steam Production Plant dismantlement costs of $68 million in 2011-year dollars, which is $178 per kW. However, the depreciation expense for Sundt Steam Production Plant proposed by TEP in this case assumes $295 per kW. TEP's $295 per kW is based on the expected lower value of dollars decades from now when the Sundt Steam Production Plant retires but would be collected from current ratepayers in current dollars. This is an unreasonable proposal. I recommend estimating the dismantlement costs in current dollars.

Q. What are dismantlement costs?

A. Dismantlement costs represent the expected future net costs of the future demolition of the production units. This demolition occurs after the production units have been retired from service.[18]

Q. How are these dismantlement costs estimated?

A. TEP's dismantlement costs are estimated by an independent engineering firm. As stated in response to discovery:

> "The "Dismantlement" cost as indicated for each respective year was obtained from the decommissioning study performed by an independent engineering firm, who typically issues a final report upon completion of the engineering study."[19]

Q. What is Schedule RMM-5?

A. Schedule RMM-5 is TEP's response to STF 4.02 and the December 2011 "Decommissioning Study of TEP Generating Assets" prepared for TEP by Burns & McDonnell Engineering Company, Inc.

Q. Please explain how TEP inflates the dismantlement costs.

A. I will use the Sundt Steam Production Plant as the example to explain how the estimated dismantlement costs are inflated by TEP.

[18] Dismantlement costs are also referred to as terminal net salvage.
[19] TEP response to STF 4.02(a), attached as Schedule RMM-5.

Attached Schedule RMM-5 includes the estimated dismantlement costs for Sundt Steam Production Plant. The engineering study estimates Sundt Steam Production Plant dismantlement costs of $68,707,853 in 2011 dollars.[20] The engineering study states:

> "BMcD has prepared estimates in current dollars (October 1, 2011 dollars) for the dismantlement of each of the assets, and these costs are summarized in Table 1.1"[21]

Column F of Table 5 below shows how the Company inflates the dismantlement costs in 2011-year dollars to TEP's proposed year of final retirement.

Table 5:

Inflation of Dismantlement Costs

Sundt Steam Production Plant	Capacity (MW)	2011 Estimated Dismantlement Cost	TEP Inflation Rate	TEP Proposed Year of Final Retirement	TEP Inflated Future Dismantlement Cost	Effective Rate Year	Dismantlement Cost at Effective Rate Year Dollars
A	B	C	D	E	F=C*(1+D)^(E-2011)	G	H=C*(1+D)^(G-2011)
Unit 1	81	$14,614,734	2.00%	2028	$20,464,157	2017	$16,458,565
Unit 2	81	14,614,734	2.00%	2030	21,290,908	2017	16,458,565
Unit 3	104	17,984,639	2.00%	2032	27,258,712	2017	20,253,625
Unit 4	120	21,493,745	2.00%	2048	44,721,715	2017	24,205,448
Total	386	$68,707,853			$113,735,492		$77,376,202
Per kilowatt:		**$178/kW**			**$295/kW**		**$200/kW**

As Table 5 shows, for Sundt Steam Production Plant the dismantlement cost is $178 per kW in 2011-year dollars, but the TEP Depreciation Rate Study proposes to collect $295 per kW based on the lower value of future dollars in the years 2028 to 2048.

[20] Exhibit REW-1, page 77 Statement G and pages 1-2, A-1, and A-2 of Decommissioning Study provided as "STF 4.02 BandM 2011 TEP Study" in response to STF 4.02, attached as Schedule RMM-5.

[21] Page 1-2 of Decommissioning Study provided as "STF 4.02 BandM 2011 TEP Study" in response to STF 4.02, attached as Schedule RMM-5.

TEP's proposed $295 per kW is calculated in 2028-year to 2048-year dollars, but would be collected from ratepayers in the more valuable 2017-year dollars. This is an unreasonable proposal.

It is reasonable to collect the estimated future dismantlement costs from current ratepayers at current dollar levels. My recommendation is to include the dismantlement costs at the effective rate year of 2017.[22]

Q. Please explain what you mean by more valuable current dollars.

A. Due to inflation, the 2048-year dollar will have a lower purchasing power than the 2017-year dollar.

According to the US Department of Labor's Consumer Price Index for all Urban Consumers ("CPI-U"), in the past 30 years a basket of goods and services which cost $107 in 1985, costs $237 in 2015.[23] The basket of goods and services costs over twice as much in 2015-year dollars as it did in 1985-year dollars.[24] In other words, a 2015-year dollar is worth only 45¢ compared to a 1985-year dollar.[25]

Q. What is Schedule RMM-6?

A. Schedule RMM-6 is Table 24 from the CPI-U March 2016 report referenced above.

[22] Page 1 of TEP's Application in this proceeding states: "Application for new rates to be effective no later than January 1, 2017."
[23] The most recent publication of the US Department of Labor's Bureau of Labor Statistics Consumer Price Index is publically available at http://www.bls.gov/cpi/#tables. See Schedule RMM-6.
[24] $237.017 average for 2015 basket/$107.6 for 1985 basket = 2.2 times.
[25] $107.6 for 1985 basket /$237.017 average for 2015 basket * $1.00 = $0.454.

Q. Does the annual inflation rate of 2 percent assumed in TEP's inflation of dismantlement costs include a change in the purchasing power of a dollar?

A. Yes. As a simple example using TEP's assumed 2 percent annual inflation rate, a gallon of milk that cost $3 in 2017-year dollars would cost $5.50 in 2048-year dollars.[26] Even if the gallon of milk will cost $5.50 in 2048-year dollars, it is not right to charge someone $5.50 in today's more valuable dollars.

Similarly, charging current ratepayers dismantlement costs calculated in 2048-year dollars but collected in today's more valuable dollars is not reasonable.

Q. What is your recommendation on this issue?

A. I recommend calculating the estimated dismantlement costs in current dollars. TEP's proposal collects the more valuable current dollars to pay for the inflated future estimated dismantlement costs.

For example, I recommend collecting Sundt Steam Production Plant dismantlement costs of $200 per kW in 2017-year dollars in 2017;[27] instead of collecting TEP's proposed $295 per kW in 2028-year to 2048-year dollars from the ratepayers in the more valuable 2017-year dollars.

CONCLUSION

Q. What are your recommendations?

A. For the reasons stated above, I recommend that the Staff-proposed depreciation rates shown on Schedule RMM-1 be approved for TEP in Arizona.

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[26] Assuming 2% inflation for 31 years. $3.00 * (1+2%)^(31) = $5.54.
[27] Page 1 of TEP's Application in this proceeding states: "Application for new rates to be effective no later than January 1, 2017."

The Staff-proposed depreciation rates shown on Schedule RMM-1 include the following adjustments to TEP's proposed depreciation rates:

(1) I recommend a -5 percent future net salvage percent for Distribution Plant. This -5 percent future net salvage percent is supported by the actual historic net salvage percent which has averaged -4.4 percent over the last 25 years;

(2) I recommend a final retirement year of 2032 for Sundt Steam Units 1 and 2; North Loop CT Units 1, 2, and 3; and Sundt CT Units 1 and 2, which is supported by the Company's future plans for providing electric service as shown in its 2016 IRP; and

(3) I recommend that the estimated dismantlement costs be set at current dollars, instead of TEP's proposal to estimate future inflated dismantlement costs in lower value future dollars and, based on that inflated future cost, to collect from current ratepayers in the more valuable current dollars.

Q. Does this conclude your direct testimony?

A. Yes.

Tucson Electric Power Company
Comparison of Depreciation Rates and Annual Accrual Amounts

Account	Description	12/31/14 Investment	Current Approved Rate	Current Approved Annual Accrual	TEP Proposed Rate	TEP Proposed Annual Accrual	TEP Proposed Difference from Current	Staff Proposed Rate	Staff Proposed Annual Accrual	Staff Proposed Difference from Current	Staff Proposed Difference from Company
		A	B	C=A*B	D	E=A*D	F=E-C	G	H=A*G	I=H-C	J=H-E
STEAM PRODUCTION											
310.00	Rights-of-Way	5,106,662	3.03%	154,753	2.85%	145,422	(9,331)	2.64%	134,884	(19,869)	(10,538)
311.00	Structures and Improvements	205,277,689	3.70%	7,597,639	3.84%	7,892,308	294,669	3.53%	7,250,080	(347,559)	(642,228)
312.00	Boiler Plant Equipment	1,091,953,161	3.27%	35,734,150	3.55%	38,767,397	3,033,247	3.27%	35,690,262	(43,888)	(3,077,135)
314.00	Turbogenerator Units	303,041,923	3.98%	12,063,502	3.83%	11,620,981	(442,521)	3.55%	10,763,039	(1,300,463)	(857,942)
315.00	Accessory Electric Equipment	144,581,471	4.66%	6,738,957	3.77%	5,453,179	(1,285,778)	3.37%	4,867,457	(1,871,500)	(585,722)
316.00	Miscellaneous Power Plant Equipment	25,222,863	3.74%	944,112	3.37%	851,172	(92,940)	3.15%	795,209	(148,903)	(55,963)
Total Steam Production Plant		**1,775,183,769**	**3.56%**	**63,233,113**	**3.65%**	**64,730,459**	**1,497,346**	**3.35%**	**59,500,931**	**(3,732,182)**	**(5,229,528)**
OTHER PRODUCTION											
Non-Solar											
341.00	Structures and Improvements	23,403,461	2.82%	659,280	2.96%	692,380	33,100	2.74%	641,628	(17,652)	(50,752)
342.00	Fuel Holders, Products and Accessories	19,977,187	3.02%	603,947	3.03%	605,749	1,802	2.80%	559,832	(44,115)	(45,917)
343.00	Prime Movers	202,005,134	2.40%	4,857,612	2.71%	5,476,303	618,691	2.57%	5,187,869	330,257	(288,434)
344.00	Generators and Devices	105,487,225	2.27%	2,397,830	2.13%	2,248,691	(149,139)	1.99%	2,104,301	(293,529)	(144,390)
345.00	Accessory Electric Equipment	13,809,819	2.41%	333,205	2.27%	312,850	(20,355)	2.10%	289,373	(43,832)	(23,477)
346.00	Miscellaneous Power Plant Equipment	15,307,160	2.72%	416,145	2.86%	437,606	21,461	2.66%	406,729	(9,416)	(30,877)
Total Non-Solar		**379,989,986**	**2.44%**	**9,268,019**	**2.57%**	**9,773,579**	**505,560**	**2.42%**	**9,189,732**	**(78,287)**	**(583,847)**
Solar											
344.00	Generators and Devices	170,320,932	5.13%	8,737,463	3.61%	6,152,021	(2,585,442)	3.61%	6,152,021	(2,585,442)	0
Total Solar		**170,320,932**	**5.57%**	**9,486,813**	**3.61%**	**6,152,021**	**(3,334,792)**	**4.02%**	**6,848,122**	**(2,638,691)**	**696,101**
Total Other Production Plant		**550,310,918**	**3.27%**	**18,005,482**	**2.89%**	**15,925,600**	**(2,079,882)**	**2.79%**	**15,341,753**	**(2,663,729)**	**(583,847)**
DISTRIBUTION PLANT											
360.RW	Rights-of-Way	7,865,073	1.43%	112,471	1.41%	110,898	(1,573)	1.27%	99,886	(12,585)	(11,012)
361.00	Structures and Improvements	11,402,474	1.72%	196,123	1.71%	194,982	(1,141)	1.66%	189,281	(6,842)	(5,701)
362.00	Station Equipment	157,067,530	1.53%	2,403,133	1.66%	2,607,321	204,188	1.58%	2,481,667	78,534	(125,654)
364.00	Poles, Towers and Fixtures	222,006,967	1.74%	3,862,921	1.66%	3,685,316	(177,605)	1.58%	3,507,710	(355,211)	(177,606)
365.00	Overhead Conductors and Devices	175,675,966	1.63%	2,863,518	1.64%	2,881,086	17,568	1.54%	2,705,410	(158,108)	(175,676)
366.00	Underground Conduit	58,725,355	1.35%	792,792	1.36%	798,665	5,873	1.26%	739,939	(52,853)	(58,726)
367.00	Underground Conductors and Devices	297,183,135	1.87%	5,557,325	1.78%	5,289,860	(267,465)	1.65%	4,903,522	(653,803)	(386,338)

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		A	B	C=A*B	D	E=A*D	F=E-C	G	H=A*G	I=H-C	J=H-E
368.OH	Line Transformers - Overhead	103,657,922	1.87%	1,938,403	1.75%	1,814,014	(124,389)	1.63%	1,689,624	(248,779)	(124,390)
368.UG	Line Transformers - Underground	172,890,932	2.09%	3,613,420	1.97%	3,405,951	(207,469)	1.83%	3,163,904	(449,516)	(242,047)
369.OH	Services - Overhead	17,542,236	1.85%	324,531	1.83%	321,023	(3,508)	1.66%	291,201	(33,330)	(29,822)
369.UG	Services - Underground	112,947,714	1.52%	1,716,805	1.52%	1,716,805	0	1.44%	1,626,447	(90,358)	(90,358)
370.00	Meters	44,869,823	3.29%	1,476,217	4.61%	2,068,499	592,282	4.44%	1,992,220	516,003	(76,279)
373.00	Street Lighting and Signal Systems	11,778,362	1.77%	208,477	1.76%	207,299	(1,178)	1.62%	190,809	(17,668)	(16,490)
Total Distribution Plant		**1,393,613,489**	**1.80%**	**25,066,136**	**1.80%**	**25,101,719**	**35,583**	**1.69%**	**23,581,622**	**(1,484,514)**	**(1,520,097)**
GENERAL PLANT											
Depreciable											
390.00	Structures and Improvements	135,680,348	2.64%	3,581,962	2.68%	3,636,234	54,272	2.68%	3,636,234	54,272	0
392.C0	Transportation - Class 0	1,238,946	4.23%	52,408	4.28%	53,027	619	4.28%	53,027	619	0
392.C1	Transportation - Class 1	7,718,183	10.62%	819,671	10.77%	831,248	11,577	10.77%	831,248	11,577	0
392.C2	Transportation - Class 2	3,839,907	10.47%	402,039	10.65%	408,950	6,911	10.65%	408,950	6,911	0
392.C3	Transportation - Class 3	2,076,936	9.15%	190,040	9.47%	196,686	6,646	9.47%	196,686	6,646	0
392.C4	Transportation - Class 4	2,935,027	6.01%	176,395	6.24%	183,146	6,751	6.24%	183,146	6,751	0
392.C5	Transportation - Class 5	7,982,715	6.23%	497,323	6.56%	523,666	26,343	6.56%	523,666	26,343	0
392.C6	Transportation - Class 6	365,200	5.65%	20,634	5.77%	21,072	438	5.77%	21,072	438	0
392.C7	Transportation - Class 7	1,047,216	5.94%	62,205	6.12%	64,090	1,885	6.12%	64,090	1,885	0
392.C8	Transportation - Class 8	9,957,500	6.37%	634,293	6.66%	663,170	28,877	6.66%	663,170	28,877	0
392.C9	Transportation - Class 9	4,252,286	3.96%	168,391	3.41%	145,003	(23,388)	3.41%	145,003	(23,388)	0
396.00	Power Operatied Equipment	11,860,940	6.24%	740,123	6.66%	789,938	49,815	6.66%	789,938	49,815	0
397.EM	EMS and SCADA Equipment	11,304,371	4.96%	560,697	5.12%	578,784	18,087	5.12%	578,784	18,087	0
Total Depreciable		**200,259,575**	**3.95%**	**7,906,181**	**4.04%**	**8,095,014**	**188,833**	**4.04%**	**8,095,014**	**188,833**	**0**
Amortizable											
391.00	Furniture and Office Equipment	23,964,411	4.15%	993,514	4.15%	993,514	0	4.15%	993,514	0	0
391.20	Network and Data Equipment	29,359,636	18.68%	5,484,102	18.68%	5,484,102	0	18.68%	5,484,102	0	0
393.00	Stores Equipment	1,852,479	6.35%	117,635	6.35%	117,635	0	6.35%	117,635	0	0
394.00	Tools, Shop and Garage Equipment	6,934,368	5.72%	396,576	5.72%	396,576	0	5.72%	396,576	0	0
395.00	Laboratory Equipment	5,091,270	5.78%	294,185	5.78%	294,185	0	5.78%	294,185	0	0
397.20	Telecommunications Equipment	57,456,141	6.59%	3,785,287	6.59%	3,785,287	0	6.59%	3,785,287	0	0
398.00	Miscellaneous Equipment	4,348,209	5.00%	217,244	5.00%	217,244	0	5.00%	217,244	0	0

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		A	B	C=A*B	D	E=A*D	F=E-C	G	H=A*G	I=H-C	J=H-E
Total Amortizable		**129,006,514**	**8.75%**	**11,288,543**	**8.75%**	**11,288,543**	**0**	**8.75%**	**11,288,543**	**0**	**0**
Total General Plant		**329,266,089**	**5.83%**	**19,194,724**	**5.89%**	**19,383,557**	**188,833**	**5.89%**	**19,383,557**	**188,833**	**0**
SUBTOTAL		**4,048,374,265**	**3.10%**	**125,499,455**	**3.09%**	**125,141,335**	**(358,120)**	**2.91%**	**117,807,862**	**(7,691,593)**	**(7,333,473)**
NET SALVAGE											
108.02	Distribution	1,393,613,489	0.27%	3,762,756	0.25%	3,484,034	(278,722)	0.08%	1,114,891	(2,647,865)	(2,369,143)
Total Net Salvage		**1,393,613,489**	**0.27%**	**3,762,756**	**0.25%**	**3,484,034**	**(278,722)**	**0.08%**	**1,114,891**	**(2,647,865)**	**(2,369,143)**
TOTAL UTILITY		**4,048,374,265**	**3.19%**	**129,262,211**	**3.18%**	**128,625,369**	**(636,842)**	**2.94%**	**118,922,753**	**(10,339,458)**	**(9,702,616)**
STEAM PRODUCTION (by Unit)											
Four Corners											
310.00	Rights-of-Way	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
311.00	Structures and Improvements	2,982,777	2.37%	70,639	2.62%	78,202	7,563	2.53%	75,524	4,885	(2,678)
312.00	Boiler Plant Equipment	76,402,061	1.74%	1,330,821	1.70%	1,295,173	(35,648)	1.60%	1,222,732	(108,089)	(72,441)
314.00	Turbogenerator Units	12,359,480	2.46%	304,488	2.16%	267,164	(37,324)	2.07%	255,523	(48,965)	(11,641)
315.00	Accessory Electric Equipment	4,390,980	3.68%	161,525	4.24%	186,103	24,578	4.16%	182,607	21,082	(3,496)
316.00	Miscellaneous Power Plant Equipment	3,832,234	2.57%	98,467	2.44%	93,473	(4,994)	2.34%	89,833	(8,634)	(3,640)
Total Four Corners		**99,967,532**	**1.97%**	**1,965,940**	**1.92%**	**1,920,115**	**(45,825)**	**1.83%**	**1,826,219**	**(139,721)**	**(93,896)**
Four Corners Unit 4											
310.00	Rights-of-Way	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
311.00	Structures and Improvements	1,524,414	2.29%	34,909	2.48%	37,806	2,897	2.40%	36,586	1,677	(1,220)
312.00	Boiler Plant Equipment	39,609,538	1.66%	657,518	1.57%	621,869	(35,649)	1.48%	586,221	(71,297)	(35,648)
314.00	Turbogenerator Units	7,179,362	2.56%	183,791	2.17%	155,792	(27,999)	2.08%	149,331	(34,460)	(6,461)
315.00	Accessory Electric Equipment	2,274,836	4.04%	91,903	4.06%	92,358	455	3.99%	90,766	(1,137)	(1,592)
316.00	Miscellaneous Power Plant Equipment	1,929,161	2.49%	48,036	2.31%	44,564	(3,472)	2.22%	42,827	(5,209)	(1,737)
Total Four Corners Unit 4		**52,517,311**	**1.93%**	**1,016,157**	**1.81%**	**952,389**	**(63,768)**	**1.72%**	**905,731**	**(110,426)**	**(46,658)**
Four Corners Unit 5											
310.00	Rights-of-Way	0	0.00%	0	0.00%	0	0	0.00%	0	0	0

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		A	B	C=A*B	D	E=A*D	F=E-C	G	H=A*G	I=H-C	J=H-E
311.00	Structures and Improvements	1,458,363	2.45%	35,730	2.77%	40,396	4,666	2.67%	38,938	3,208	(1,458)
312.00	Boiler Plant Equipment	36,792,523	1.83%	673,303	1.83%	673,304	1	1.73%	636,511	(36,792)	(36,793)
314.00	Turbogenerator Units	5,180,118	2.33%	120,697	2.15%	111,372	(9,325)	2.05%	106,192	(14,505)	(5,180)
315.00	Accessory Electric Equipment	2,116,144	3.29%	69,622	4.43%	93,745	24,123	4.34%	91,841	22,219	(1,904)
316.00	Miscellaneous Power Plant Equipment	1,903,073	2.65%	50,431	2.57%	48,909	(1,522)	2.47%	47,006	(3,425)	(1,903)
Total Four Corners Unit 5		**47,450,221**	**2.00%**	**949,783**	**2.04%**	**967,726**	**17,943**	**1.94%**	**920,488**	**(29,295)**	**(47,238)**
Navajo											
310.00	Rights-of-Way	12,229	0.30%	37	0.81%	99	62	0.73%	89	52	(10)
311.00	Structures and Improvements	18,655,156	1.53%	286,342	2.71%	506,229	219,887	2.64%	492,221	205,879	(14,008)
312.00	Boiler Plant Equipment	88,544,201	1.76%	1,560,724	3.31%	2,933,882	1,373,158	3.24%	2,867,875	1,307,151	(66,007)
314.00	Turbogenerator Units	20,255,526	1.61%	325,402	3.33%	674,427	349,025	3.25%	658,895	333,493	(15,532)
315.00	Accessory Electric Equipment	14,829,858	2.00%	296,511	4.10%	607,610	311,099	4.02%	596,035	299,524	(11,575)
316.00	Miscellaneous Power Plant Equipment	4,518,597	1.69%	76,212	3.01%	136,142	59,930	2.93%	132,503	56,291	(3,639)
Total Navajo		**146,815,567**	**1.73%**	**2,545,228**	**3.31%**	**4,858,389**	**2,313,161**	**3.23%**	**4,747,618**	**2,202,390**	**(110,771)**
Navajo Unit 1											
310.00	Rights-of-Way	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
311.00	Structures and Improvements	3,190,563	0.74%	23,610	4.33%	138,151	114,541	4.29%	136,875	113,265	(1,276)
312.00	Boiler Plant Equipment	27,198,582	1.87%	508,613	6.30%	1,713,511	1,204,898	6.26%	1,702,631	1,194,018	(10,880)
314.00	Turbogenerator Units	6,860,989	1.67%	114,579	6.32%	433,615	319,036	6.27%	430,184	315,605	(3,431)
315.00	Accessory Electric Equipment	3,544,300	1.60%	56,709	8.88%	314,734	258,025	8.84%	313,316	256,607	(1,418)
316.00	Miscellaneous Power Plant Equipment	471,227	0.72%	3,393	4.20%	19,791	16,398	4.16%	19,603	16,210	(188)
Total Navajo Unit 1		**41,265,661**	**1.71%**	**706,904**	**6.35%**	**2,619,802**	**1,912,898**	**6.31%**	**2,602,610**	**1,895,706**	**(17,192)**
Navajo Unit 2											
310.00	Rights-of-Way	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
311.00	Structures and Improvements	1,802,685	1.06%	19,109	1.51%	27,220	8,111	1.41%	25,418	6,309	(1,802)
312.00	Boiler Plant Equipment	26,882,286	1.61%	432,805	1.80%	483,881	51,076	1.70%	456,999	24,194	(26,882)
314.00	Turbogenerator Units	6,926,050	1.72%	119,128	1.94%	134,365	15,237	1.84%	127,439	8,311	(6,926)
315.00	Accessory Electric Equipment	3,172,330	1.73%	54,882	2.18%	69,157	14,275	2.09%	66,302	11,420	(2,855)
316.00	Miscellaneous Power Plant Equipment	515,874	0.94%	4,850	1.03%	5,314	464	0.93%	4,798	(52)	(516)
Total Navajo Unit 2		**39,299,225**	**1.61%**	**630,774**	**1.83%**	**719,937**	**89,163**	**1.73%**	**680,955**	**50,181**	**(38,982)**

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Account	Description	12/31/14 Investment	Current Approved		TEP Proposed			Staff Proposed			
			Rate	Annual Accrual	Rate	Annual Accrual	Difference from Current	Rate	Annual Accrual	Difference from Current	Difference from Company
		A	B	C=A*B	D	E=A*D	F=E-C	G	H=A*G	I=H-C	J=H-E
Navajo Unit 3											
310.00	Rights-of-Way	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
311.00	Structures and Improvements	3,681,511	1.06%	39,024	1.18%	43,442	4,418	1.10%	40,497	1,473	(2,945)
312.00	Boiler Plant Equipment	27,718,514	1.66%	460,128	1.91%	529,424	69,296	1.83%	507,249	47,121	(22,175)
314.00	Turbogenerator Units	6,178,944	1.29%	79,708	1.48%	91,448	11,740	1.40%	86,505	6,797	(4,943)
315.00	Accessory Electric Equipment	5,139,872	1.44%	74,014	1.68%	86,350	12,336	1.59%	81,724	7,710	(4,626)
316.00	Miscellaneous Power Plant Equipment	549,362	0.81%	4,449	1.05%	5,768	1,319	0.95%	5,219	770	(549)
Total Navajo Unit 3		**43,268,203**	**1.52%**	**657,323**	**1.75%**	**756,432**	**99,109**	**1.67%**	**721,194**	**63,871**	**(35,238)**
Navajo Common											
310.00	Rights-of-Way	12,229	0.31%	37	0.81%	99	62	0.73%	89	52	(10)
311.00	Structures and Improvements	9,980,397	2.05%	204,599	2.98%	297,416	92,817	2.90%	289,432	84,833	(7,984)
312.00	Boiler Plant Equipment	6,744,819	2.36%	159,178	3.07%	207,066	47,888	2.98%	200,996	41,818	(6,070)
314.00	Turbogenerator Units	289,543	4.14%	11,987	5.18%	14,999	3,012	5.10%	14,767	2,780	(232)
315.00	Accessory Electric Equipment	2,973,356	3.73%	110,906	4.62%	137,369	26,463	4.53%	134,693	23,787	(2,676)
316.00	Miscellaneous Power Plant Equipment	2,982,134	2.13%	63,520	3.53%	105,269	41,749	3.45%	102,884	39,364	(2,385)
Total Navajo Common		**22,982,478**	**2.39%**	**550,227**	**3.32%**	**762,218**	**211,991**	**3.23%**	**742,860**	**192,633**	**(19,358)**
San Juan											
310.00	Rights-of-Way	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
311.00	Structures and Improvements	14,437,744	1.87%	269,902	8.30%	1,198,011	928,109	8.16%	1,178,035	908,133	(19,976)
312.00	Boiler Plant Equipment	154,506,908	3.20%	4,936,573	8.53%	13,184,314	8,247,741	8.37%	12,924,514	7,987,941	(259,800)
314.00	Turbogenerator Units	44,295,673	2.24%	992,223	8.31%	3,680,970	2,688,747	8.17%	3,618,956	2,626,733	(62,014)
315.00	Accessory Electric Equipment	10,063,526	2.28%	229,449	8.36%	841,311	611,862	8.22%	827,222	597,773	(14,089)
316.00	Miscellaneous Power Plant Equipment	2,009,555	1.70%	34,250	8.31%	167,081	132,831	8.18%	164,337	130,087	(2,744)
Total San Juan		**225,313,406**	**2.87%**	**6,462,397**	**8.46%**	**19,071,687**	**12,609,290**	**8.31%**	**18,713,065**	**12,250,668**	**(358,622)**
San Juan Unit 1											
310.00	Rights-of-Way	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
311.00	Structures and Improvements	14,268,404	1.87%	266,820	8.30%	1,184,277	917,457	8.16%	1,164,302	897,482	(19,975)
312.00	Boiler Plant Equipment	146,453,029	2.63%	3,851,715	8.37%	12,258,118	8,406,403	8.23%	12,053,084	8,201,369	(205,034)
314.00	Turbogenerator Units	44,295,673	2.24%	992,223	8.31%	3,680,970	2,688,747	8.17%	3,618,956	2,626,733	(62,014)

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Account	Description	12/31/14 Investment	Current Approved Rate	Current Approved Annual Accrual	TEP Proposed Rate	TEP Proposed Annual Accrual	TEP Proposed Difference from Current	Staff Proposed Rate	Staff Proposed Annual Accrual	Staff Proposed Difference from Current	Staff Proposed Difference from Company
		A	B	C=A*B	D	E=A*D	F=E-C	G	H=A*G	I=H-C	J=H-E
315.00	Accessory Electric Equipment	10,063,526	2.28%	229,449	8.36%	841,311	611,862	8.22%	827,222	597,773	(14,089)
316.00	Miscellaneous Power Plant Equipment	1,960,172	1.71%	33,519	8.32%	163,086	129,567	8.18%	160,342	126,823	(2,744)
Total San Juan Unit 1		**217,040,804**	**2.48%**	**5,373,726**	**8.35%**	**18,127,762**	**12,754,036**	**8.21%**	**17,823,906**	**12,450,180**	**(303,856)**
San Juan Common											
310.00	Rights-of-Way	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
311.00	Structures and Improvements	169,340	1.82%	3,082	8.11%	13,734	10,652	8.11%	13,733	10,651	(1)
312.00	Boiler Plant Equipment	8,053,879	13.47%	1,084,858	11.50%	926,196	(158,662)	10.82%	871,430	(213,428)	(54,766)
314.00	Turbogenerator Units	0	2.50%	0	0.00%	0	0	0.00%	0	0	0
315.00	Accessory Electric Equipment	0	2.30%	0	0.00%	0	0	0.00%	0	0	0
316.00	Miscellaneous Power Plant Equipment	49,383	1.48%	731	8.09%	3,995	3,264	8.09%	3,995	3,264	0
Total San Juan Common		**8,272,602**	**13.16%**	**1,088,671**	**11.41%**	**943,925**	**(144,746)**	**10.75%**	**889,158**	**(199,513)**	**(54,767)**
Springerville											
310.00	Rights-of-Way	5,094,433	3.04%	154,716	2.85%	145,323	(9,393)	2.65%	134,795	(19,921)	(10,528)
311.00	Structures and Improvements	141,726,641	3.76%	5,335,428	3.44%	4,877,730	(457,698)	3.20%	4,533,528	(801,900)	(344,202)
312.00	Boiler Plant Equipment	641,687,365	3.23%	20,720,796	2.51%	16,115,497	(4,605,299)	2.26%	14,479,685	(6,241,111)	(1,635,812)
314.00	Turbogenerator Units	173,649,915	3.06%	5,305,725	2.32%	4,023,940	(1,281,785)	2.23%	3,879,396	(1,426,329)	(144,544)
315.00	Accessory Electric Equipment	75,864,618	3.38%	2,563,333	2.09%	1,583,656	(979,677)	1.96%	1,483,627	(1,079,706)	(100,029)
316.00	Miscellaneous Power Plant Equipment	12,528,984	4.05%	507,452	2.49%	312,217	(195,235)	2.35%	294,928	(212,524)	(17,289)
Total Springerville		**1,050,551,956**	**3.29%**	**34,587,450**	**2.58%**	**27,058,363**	**(7,529,087)**	**2.36%**	**24,805,960**	**(9,781,490)**	**(2,252,403)**
Springerville Unit 1											
310.00	Rights-of-Way	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
311.00	Structures and Improvements	20,076,015	7.98%	1,602,066	2.14%	429,627	(1,172,439)	2.07%	415,574	(1,186,492)	(14,053)
312.00	Boiler Plant Equipment	185,682,490	6.18%	11,475,178	2.06%	3,825,059	(7,650,119)	1.98%	3,676,513	(7,798,665)	(148,546)
314.00	Turbogenerator Units	49,547,312	5.72%	2,834,106	2.05%	1,015,720	(1,818,386)	1.97%	976,082	(1,858,024)	(39,638)
315.00	Accessory Electric Equipment	21,214,167	6.09%	1,291,942	1.81%	383,976	(907,966)	1.73%	367,005	(924,937)	(16,971)
316.00	Miscellaneous Power Plant Equipment	3,277,742	8.69%	284,836	2.21%	72,438	(212,398)	2.15%	70,471	(214,365)	(1,967)
Total Springerville Unit 1		**279,797,726**	**6.25%**	**17,488,128**	**2.05%**	**5,726,820**	**(11,761,308)**	**1.97%**	**5,505,645**	**(11,982,483)**	**(221,175)**
Springerville Unit 1 Common											
310.00	Rights-of-Way	1,143,496	0.00%	0	2.03%	23,213	23,213	1.92%	21,955	21,955	(1,258)

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		A	B	C=A*B	D	E=A*D	F=E-C	G	H=A*G	I=H-C	J=H-E
311.00	Structures and Improvements	52,492,826	3.01%	1,580,034	2.28%	1,196,837	(383,197)	2.05%	1,076,103	(503,931)	(120,734)
312.00	Boiler Plant Equipment	14,854,799	4.24%	629,843	2.26%	335,718	(294,125)	2.02%	300,067	(329,776)	(35,651)
314.00	Turbogenerator Units	1,264,322	1.83%	23,137	2.19%	27,688	4,551	1.95%	24,654	1,517	(3,034)
315.00	Accessory Electric Equipment	9,627,097	4.35%	418,779	2.11%	203,131	(215,648)	1.84%	177,139	(241,640)	(25,992)
316.00	Miscellaneous Power Plant Equipment	1,959,012	3.72%	72,875	2.11%	41,335	(31,540)	1.85%	36,242	(36,633)	(5,093)
Total Springerville Unit 1 Common		**81,341,552**	**3.35%**	**2,724,668**	**2.25%**	**1,827,922**	**(896,746)**	**2.01%**	**1,636,160**	**(1,088,508)**	**(191,762)**
Springerville Unit 2											
310.00	Rights-of-Way	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
311.00	Structures and Improvements	36,540,030	2.01%	734,455	2.31%	844,075	109,620	2.21%	807,535	73,080	(36,540)
312.00	Boiler Plant Equipment	295,922,545	2.02%	5,977,636	2.27%	6,717,442	739,806	2.18%	6,451,111	473,475	(266,331)
314.00	Turbogenerator Units	122,055,348	1.98%	2,416,695	2.40%	2,929,328	512,633	2.32%	2,831,684	414,989	(97,644)
315.00	Accessory Electric Equipment	42,346,939	1.82%	770,714	2.00%	846,938	76,224	1.90%	804,592	33,878	(42,346)
316.00	Miscellaneous Power Plant Equipment	6,624,669	1.82%	120,569	2.27%	150,380	29,811	2.17%	143,755	23,186	(6,625)
Total Springerville Unit 2		**503,489,531**	**1.99%**	**10,020,069**	**2.28%**	**11,488,163**	**1,468,094**	**2.19%**	**11,038,677**	**1,018,608**	**(449,486)**
Springerville Unit 2 Common (Leasehold Imp.)											
310.00	Rights-of-Way	2,280,838	2.80%	63,863	3.86%	88,040	24,177	3.60%	82,110	18,247	(5,930)
311.00	Structures and Improvements	32,617,770	4.35%	1,418,873	7.38%	2,407,191	988,318	6.85%	2,234,317	815,444	(172,874)
312.00	Boiler Plant Equipment	6,282,729	5.50%	345,550	8.61%	540,943	195,393	8.10%	508,901	163,351	(32,042)
314.00	Turbogenerator Units	782,933	4.06%	31,787	6.54%	51,204	19,417	6.00%	46,976	15,189	(4,228)
315.00	Accessory Electric Equipment	2,676,415	3.06%	81,898	5.59%	149,611	67,713	5.04%	134,891	52,993	(14,720)
316.00	Miscellaneous Power Plant Equipment	667,561	4.37%	29,172	7.20%	48,064	18,892	6.66%	44,460	15,288	(3,604)
Total Springerville Unit 2 Common		**45,308,246**	**4.35%**	**1,971,143**	**7.25%**	**3,285,053**	**1,313,910**	**6.74%**	**3,051,655**	**1,080,512**	**(233,398)**
Springerville Coal Handling											
310.00	Rights-of-Way	1,670,099	5.44%	90,853	2.04%	34,070	(56,783)	1.84%	30,730	(60,123)	(3,340)
311.00	Structures and Improvements	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
312.00	Boiler Plant Equipment	138,944,802	1.65%	2,292,589	3.38%	4,696,335	2,403,746	2.55%	3,543,092	1,250,503	(1,153,243)
314.00	Turbogenerator Units	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
315.00	Accessory Electric Equipment	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
316.00	Miscellaneous Power Plant Equipment	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
Total Springerville Coal Handling		**140,614,901**	**1.70%**	**2,383,442**	**3.36%**	**4,730,405**	**2,346,963**	**2.54%**	**3,573,822**	**1,190,380**	**(1,156,583)**

Tucson Electric Power Company
Comparison of Depreciation Rates and Annual Accrual Amounts

Account	Description	12/31/14 Investment	Current Approved Rate	Current Approved Annual Accrual	TEP Proposed Rate	TEP Proposed Annual Accrual	TEP Proposed Difference from Current	Staff Proposed Rate	Staff Proposed Annual Accrual	Staff Proposed Difference from Current	Staff Proposed Difference from Company
		A	B	C=A*B	D	E=A*D	F=E-C	G	H=A*G	I=H-C	J=H-E
Sundt											
310.00	Rights-of-Way	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
311.00	Structures and Improvements	27,475,371	5.95%	1,635,328	4.48%	1,232,136	(403,192)	3.53%	970,771	(664,557)	(261,365)
312.00	Boiler Plant Equipment	130,812,626	5.49%	7,185,236	4.00%	5,238,531	(1,946,705)	3.21%	4,195,456	(2,989,780)	(1,043,075)
314.00	Turbogenerator Units	52,481,329	9.79%	5,135,664	5.67%	2,974,480	(2,161,184)	4.48%	2,350,268	(2,785,396)	(624,212)
315.00	Accessory Electric Equipment	39,432,489	8.85%	3,488,139	5.67%	2,234,499	(1,253,640)	4.51%	1,777,967	(1,710,172)	(456,532)
316.00	Miscellaneous Power Plant Equipment	2,333,493	9.76%	227,731	6.10%	142,259	(85,472)	4.87%	113,607	(114,124)	(28,652)
Total Sundt		**252,535,308**	**7.00%**	**17,672,098**	**4.68%**	**11,821,905**	**(5,850,193)**	**3.73%**	**9,408,069**	**(8,264,029)**	**(2,413,836)**
Sundt Unit 1											
310.00	Rights-of-Way	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
311.00	Structures and Improvements	3,926,062	15.32%	601,473	7.76%	304,662	(296,811)	5.43%	213,185	(388,288)	(91,477)
312.00	Boiler Plant Equipment	13,782,181	15.42%	2,125,212	6.91%	952,349	(1,172,863)	4.87%	671,192	(1,454,020)	(281,157)
314.00	Turbogenerator Units	10,237,507	17.84%	1,826,371	7.69%	787,264	(1,039,107)	5.44%	556,920	(1,269,451)	(230,344)
315.00	Accessory Electric Equipment	6,536,315	20.27%	1,324,911	9.54%	623,564	(701,347)	6.92%	452,313	(872,598)	(171,251)
316.00	Miscellaneous Power Plant Equipment	490,578	18.69%	91,689	9.10%	44,643	(47,046)	6.56%	32,182	(59,507)	(12,461)
Total Sundt Unit 1		**34,972,643**	**17.07%**	**5,969,656**	**7.76%**	**2,712,482**	**(3,257,174)**	**5.51%**	**1,925,793**	**(4,043,863)**	**(786,689)**
Sundt Unit 2											
310.00	Rights-of-Way	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
311.00	Structures and Improvements	2,812,689	13.73%	386,182	8.05%	226,421	(159,761)	6.30%	177,199	(208,983)	(49,222)
312.00	Boiler Plant Equipment	14,371,609	13.62%	1,957,413	6.70%	962,898	(994,515)	5.09%	731,515	(1,225,898)	(231,383)
314.00	Turbogenerator Units	8,451,923	13.41%	1,133,403	6.35%	536,697	(596,706)	4.77%	403,157	(730,246)	(133,540)
315.00	Accessory Electric Equipment	6,205,700	16.42%	1,018,976	9.19%	570,304	(448,672)	7.35%	456,119	(562,857)	(114,185)
316.00	Miscellaneous Power Plant Equipment	383,824	15.52%	59,570	8.73%	33,508	(26,062)	6.95%	26,676	(32,894)	(6,832)
Total Sundt Unit 2		**32,225,745**	**14.14%**	**4,555,544**	**7.23%**	**2,329,828**	**(2,225,716)**	**5.57%**	**1,794,666**	**(2,760,878)**	**(535,162)**
Sundt Unit 3											
310.00	Rights-of-Way	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
311.00	Structures and Improvements	2,762,012	11.54%	318,737	7.03%	194,169	(124,568)	5.85%	161,578	(157,159)	(32,591)
312.00	Boiler Plant Equipment	11,980,831	10.84%	1,298,722	6.68%	800,319	(498,403)	5.48%	656,550	(642,172)	(143,769)
314.00	Turbogenerator Units	14,830,615	11.91%	1,766,326	6.91%	1,024,796	(741,530)	5.73%	849,794	(916,532)	(175,002)

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315.00	Accessory Electric Equipment	6,140,139	12.31%	755,851	6.74%	413,846	(342,005)	5.56%	341,392	(414,459)	(72,454)
316.00	Miscellaneous Power Plant Equipment	404,717	13.45%	54,435	7.79%	31,528	(22,907)	6.65%	26,914	(27,521)	(4,614)
Total Sundt Unit 3		**36,118,314**	**11.61%**	**4,194,071**	**6.82%**	**2,464,658**	**(1,729,413)**	**5.64%**	**2,036,227**	**(2,157,844)**	**(428,431)**
Sundt Unit 4											
310.00	Rights-of-Way	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
311.00	Structures and Improvements	17,974,608	1.83%	328,936	2.82%	506,884	177,948	2.33%	418,808	89,872	(88,076)
312.00	Boiler Plant Equipment	80,576,055	1.82%	1,466,484	2.74%	2,207,784	741,300	2.26%	1,821,019	354,535	(386,765)
314.00	Turbogenerator Units	18,961,284	2.16%	409,564	3.30%	625,723	216,159	2.85%	540,397	130,833	(85,326)
315.00	Accessory Electric Equipment	20,550,335	1.89%	388,401	3.05%	626,785	238,384	2.57%	528,144	139,743	(98,641)
316.00	Miscellaneous Power Plant Equipment	1,054,374	2.09%	22,037	3.09%	32,580	10,543	2.64%	27,835	5,798	(4,745)
Total Sundt Unit 4		**139,116,656**	**1.88%**	**2,615,422**	**2.88%**	**3,999,756**	**1,384,334**	**2.40%**	**3,336,203**	**720,781**	**(663,553)**
Sundt Solar Booster (Areva)											
310.00	Rights-of-Way	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
311.00	Structures and Improvements	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
312.00	Boiler Plant Equipment	10,101,950	3.34%	337,405	3.12%	315,181	(22,224)	3.12%	315,181	(22,224)	0
314.00	Turbogenerator Units	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
315.00	Accessory Electric Equipment	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
316.00	Miscellaneous Power Plant Equipment	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
Total Sundt Solar Booster (Areva)		**10,101,950**	**3.34%**	**337,405**	**3.12%**	**315,181**	**(22,224)**	**3.12%**	**315,181**	**(22,224)**	**0**
OTHER PRODUCTION (by Unit)											
DeMoss Petrie Gas Unit 1											
341.00	Structures and Improvements	761,988	2.65%	20,193	2.82%	21,488	1,295	2.71%	20,650	457	(838)
342.00	Fuel Holders, Products and Accessories	750,386	2.51%	18,835	2.43%	18,235	(600)	2.29%	17,184	(1,651)	(1,051)
343.00	Prime Movers	76,766	3.17%	2,433	2.87%	2,204	(229)	2.84%	2,180	(253)	(24)
344.00	Generators and Devices	30,772,866	2.51%	772,399	2.43%	747,780	(24,619)	2.30%	707,776	(64,623)	(40,004)
345.00	Accessory Electric Equipment	861,492	2.51%	21,623	2.34%	20,159	(1,464)	2.27%	19,556	(2,067)	(603)
346.00	Miscellaneous Power Plant Equipment	376,605	2.60%	9,792	2.57%	9,679	(113)	2.43%	9,152	(640)	(527)
Total DeMoss Petrie Gas Unit 1		**33,600,103**	**2.52%**	**845,275**	**2.44%**	**819,545**	**(25,730)**	**2.31%**	**776,497**	**(68,778)**	**(43,048)**

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		A	B	C=A*B	D	E=A*D	F=E-C	G	H=A*G	I=H-C	J=H-E
Gila River											
341.00	Structures and Improvements	8,508,950	2.26%	192,303	2.62%	222,552	30,249	2.50%	212,341	20,038	(10,211)
342.00	Fuel Holders, Products and Accessories	6,783,045	2.26%	153,296	2.60%	176,448	23,152	2.48%	168,309	15,013	(8,139)
343.00	Prime Movers	188,744,730	2.26%	4,265,631	2.64%	4,976,898	711,267	2.52%	4,750,404	484,773	(226,494)
344.00	Generators and Devices	32,783,434	2.26%	740,906	2.57%	842,534	101,628	2.45%	803,194	62,288	(39,340)
345.00	Accessory Electric Equipment	9,030,698	2.26%	204,094	2.59%	233,642	29,548	2.47%	222,806	18,712	(10,836)
346.00	Miscellaneous Power Plant Equipment	6,799,960	2.26%	153,679	2.61%	177,479	23,800	2.49%	169,319	15,640	(8,160)
Total Gila River		**252,650,817**	**2.26%**	**5,709,909**	**2.62%**	**6,629,553**	**919,644**	**2.50%**	**6,326,373**	**616,464**	**(303,180)**
Gila River Unit 3											
341.00	Structures and Improvements	957,417	2.26%	21,638	2.58%	24,702	3,064	2.46%	23,552	1,914	(1,150)
342.00	Fuel Holders, Products and Accessories	178,424	2.26%	4,032	2.65%	4,728	696	2.53%	4,514	482	(214)
343.00	Prime Movers	181,571,712	2.26%	4,103,521	2.63%	4,775,336	671,815	2.51%	4,557,450	453,929	(217,886)
344.00	Generators and Devices	32,783,434	2.26%	740,906	2.57%	842,534	101,628	2.45%	803,194	62,288	(39,340)
345.00	Accessory Electric Equipment	6,860,554	2.26%	155,049	2.58%	177,002	21,953	2.46%	168,770	13,721	(8,232)
346.00	Miscellaneous Power Plant Equipment	135,558	2.26%	3,064	2.61%	3,538	474	2.49%	3,375	311	(163)
Total Gila River Unit 3		**222,487,099**	**2.26%**	**5,028,210**	**2.62%**	**5,827,840**	**799,630**	**2.50%**	**5,560,856**	**532,646**	**(266,984)**
Gila River Common											
341.00	Structures and Improvements	7,551,533	2.26%	170,665	2.62%	197,850	27,185	2.50%	188,788	18,123	(9,062)
342.00	Fuel Holders, Products and Accessories	6,604,621	2.26%	149,264	2.60%	171,720	22,456	2.48%	163,795	14,531	(7,925)
343.00	Prime Movers	7,173,018	2.26%	162,110	2.81%	201,562	39,452	2.69%	192,954	30,844	(8,608)
344.00	Generators and Devices	0	2.26%	0	0.00%	0	0	0.00%	0	0	0
345.00	Accessory Electric Equipment	2,170,144	2.26%	49,045	2.61%	56,640	7,595	2.49%	54,037	4,992	(2,603)
346.00	Miscellaneous Power Plant Equipment	6,664,402	2.26%	150,615	2.61%	173,941	23,326	2.49%	165,944	15,329	(7,997)
Total Gila River Common		**30,163,718**	**2.26%**	**681,699**	**2.66%**	**801,713**	**120,014**	**2.54%**	**765,517**	**83,818**	**(36,196)**
Luna											
341.00	Structures and Improvements	13,232,832	3.14%	415,510	3.30%	436,684	21,174	3.03%	400,955	(14,555)	(35,729)
342.00	Fuel Holders, Products and Accessories	11,352,383	3.14%	356,464	3.30%	374,628	18,164	3.03%	343,977	(12,487)	(30,651)
343.00	Prime Movers	11,151,074	3.16%	352,373	3.35%	373,561	21,188	3.09%	344,568	(7,805)	(28,993)
344.00	Generators and Devices	9,486,694	3.13%	296,933	3.29%	312,112	15,179	3.04%	288,395	(8,538)	(23,717)
345.00	Accessory Electric Equipment	9,647	2.57%	248	3.40%	328	80	3.14%	303	55	(25)

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		A	B	C=A*B	D	E=A*D	F=E-C	G	H=A*G	I=H-C	J=H-E
346.00	Miscellaneous Power Plant Equipment	7,424,592	3.14%	233,132	3.30%	245,012	11,880	3.03%	224,965	(8,167)	(20,047)
Total Luna		**52,657,222**	**3.14%**	**1,654,660**	**3.31%**	**1,742,325**	**87,665**	**3.04%**	**1,603,164**	**(51,496)**	**(139,161)**
North Loop Gas											
341.00	Structures and Improvements	888,601	3.52%	31,244	1.31%	11,672	(19,572)	0.87%	7,691	(23,553)	(3,981)
342.00	Fuel Holders, Products and Accessories	303,037	2.35%	7,121	2.36%	7,152	31	2.28%	6,909	(212)	(243)
343.00	Prime Movers	1,890,946	12.27%	231,937	6.40%	121,049	(110,888)	4.68%	88,444	(143,493)	(32,605)
344.00	Generators and Devices	24,062,187	2.39%	574,580	1.57%	378,598	(195,982)	1.38%	331,833	(242,747)	(46,765)
345.00	Accessory Electric Equipment	2,829,171	3.26%	92,213	2.01%	56,921	(35,292)	1.60%	45,394	(46,819)	(11,527)
346.00	Miscellaneous Power Plant Equipment	656,253	2.98%	19,542	0.92%	6,069	(13,473)	0.58%	3,836	(15,706)	(2,233)
Total North Loop Gas		**30,630,195**	**3.12%**	**956,637**	**1.90%**	**581,461**	**(375,176)**	**1.58%**	**484,107**	**(472,530)**	**(97,354)**
North Loop Gas Unit 1											
341.00	Structures and Improvements	411,070	4.88%	20,060	1.64%	6,741	(13,319)	1.10%	4,522	(15,538)	(2,219)
342.00	Fuel Holders, Products and Accessories	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
343.00	Prime Movers	678,545	10.66%	72,333	4.28%	29,042	(43,291)	3.25%	22,053	(50,280)	(6,989)
344.00	Generators and Devices	3,582,271	2.94%	105,319	0.23%	8,239	(97,080)	-0.06%	(2,149)	(107,468)	(10,388)
345.00	Accessory Electric Equipment	790,955	4.55%	35,988	1.70%	13,446	(22,542)	1.15%	9,096	(26,892)	(4,350)
346.00	Miscellaneous Power Plant Equipment	306,369	4.74%	14,522	1.35%	4,136	(10,386)	0.88%	2,696	(11,826)	(1,440)
Total North Loop Gas Unit 1		**5,769,210**	**4.30%**	**248,222**	**1.07%**	**61,604**	**(186,618)**	**0.63%**	**36,217**	**(212,005)**	**(25,387)**
North Loop Gas Unit 2											
341.00	Structures and Improvements	196,078	2.29%	4,490	0.98%	1,921	(2,569)	0.52%	1,020	(3,470)	(901)
342.00	Fuel Holders, Products and Accessories	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
343.00	Prime Movers	263,450	6.12%	16,123	13.96%	36,778	20,655	9.64%	25,397	9,274	(11,381)
344.00	Generators and Devices	3,239,719	2.11%	68,358	0.80%	25,918	(42,440)	0.39%	12,635	(55,723)	(13,283)
345.00	Accessory Electric Equipment	504,895	3.07%	15,500	2.03%	10,250	(5,250)	1.36%	6,867	(8,633)	(3,383)
346.00	Miscellaneous Power Plant Equipment	128,559	1.02%	1,311	0.15%	193	(1,118)	-0.17%	(219)	(1,530)	(412)
Total North Loop Gas Unit 2		**4,332,701**	**2.44%**	**105,782**	**1.73%**	**75,060**	**(30,722)**	**1.05%**	**45,699**	**(60,083)**	**(29,361)**
North Loop Gas Unit 3											
341.00	Structures and Improvements	196,078	2.46%	4,824	0.56%	1,098	(3,726)	0.16%	314	(4,510)	(784)
342.00	Fuel Holders, Products and Accessories	0	0.00%	0	0.00%	0	0	0.00%	0	0	0

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343.00	Prime Movers	948,951	15.12%	143,481	5.82%	55,229	(88,252)	4.32%	40,995	(102,486)	(14,234)
344.00	Generators and Devices	3,030,531	2.21%	66,975	0.30%	9,092	(57,883)	-0.04%	(1,212)	(68,187)	(10,304)
345.00	Accessory Electric Equipment	503,907	3.22%	16,225	1.65%	8,314	(7,911)	1.04%	5,241	(10,984)	(3,073)
346.00	Miscellaneous Power Plant Equipment	128,559	1.24%	1,594	-0.30%	(385)	(1,979)	-0.56%	(720)	(2,314)	(335)
Total North Loop Gas Unit 3		**4,808,026**	**4.85%**	**233,099**	**1.53%**	**73,348**	**(159,751)**	**0.93%**	**44,617**	**(188,482)**	**(28,731)**
North Loop Gas Unit 4											
341.00	Structures and Improvements	85,375	2.19%	1,870	2.24%	1,912	42	2.15%	1,836	(34)	(76)
342.00	Fuel Holders, Products and Accessories	303,037	2.35%	7,121	2.36%	7,152	31	2.28%	6,909	(212)	(243)
343.00	Prime Movers	0	0.00%	0	0.00%	0	0	0.00%	0	0	0
344.00	Generators and Devices	14,209,666	2.35%	333,928	2.36%	335,349	1,421	2.27%	322,559	(11,369)	(12,790)
345.00	Accessory Electric Equipment	1,029,414	2.38%	24,500	2.42%	24,911	411	2.35%	24,191	(309)	(720)
346.00	Miscellaneous Power Plant Equipment	92,766	2.28%	2,115	2.29%	2,125	10	2.24%	2,078	(37)	(47)
Total North Loop Gas Unit 4		**15,720,258**	**2.35%**	**369,534**	**2.36%**	**371,449**	**1,915**	**2.27%**	**357,573**	**(11,961)**	**(13,876)**
Solar Units (Generators and Devices)											
344.00	DeMoss Petrie	1,146,081	5.13%	58,794	3.20%	36,674	(22,120)	3.20%	36,674	(22,120)	0
344.00	Fort Huachuca	36,709,538	5.13%	1,883,199	3.74%	1,372,937	(510,262)	3.74%	1,372,937	(510,262)	0
344.00	HQ Rooftop	303,184	5.13%	15,553	3.68%	11,157	(4,396)	3.68%	11,157	(4,396)	0
344.00	OH Rooftop	2,594,590	5.13%	133,102	3.64%	94,443	(38,659)	3.64%	94,443	(38,659)	0
344.00	OH Test Yard	388,459	5.13%	19,928	3.25%	12,625	(7,303)	3.25%	12,625	(7,303)	0
344.00	Prairie Fire	19,036,520	5.13%	976,573	3.68%	700,544	(276,029)	3.68%	700,544	(276,029)	0
344.00	Springerville Sites 1-3 (Legacy)	28,766,605	5.13%	1,475,727	3.20%	920,531	(555,196)	3.20%	920,531	(555,196)	0
344.00	Springerville Site 4	7,873,874	5.13%	403,930	3.61%	284,247	(119,683)	3.61%	284,247	(119,683)	0
343.00	Tucson	87,198	5.13%	4,473	2.73%	2,380	(2,093)	2.73%	2,380	(2,093)	0
344.00	U of A Tech Park Site 1	7,723,832	5.13%	396,233	3.61%	278,830	(117,403)	3.61%	278,830	(117,403)	0
345.00	U of A Tech Park Site 2	19,191,952	5.13%	984,547	3.64%	698,587	(285,960)	3.64%	698,587	(285,960)	0
346.00	White Mountain	46,499,099	5.13%	2,385,404	3.74%	1,739,066	(646,338)	3.74%	1,739,066	(646,338)	0
Total Solar Units		**170,320,932**	**5.13%**	**8,737,463**	**3.61%**	**6,152,021**	**(2,585,442)**	**3.61%**	**6,152,021**	**(2,585,442)**	**0**
Sundt Gas											
341.00	Structures and Improvements	11,090	0.27%	30	-0.14%	(16)	(46)	-0.08%	(8)	(38)	8
342.00	Fuel Holders, Products and Accessories	788,336	8.66%	68,231	3.71%	29,286	(38,945)	2.98%	23,453	(44,778)	(5,833)

Tucson Electric Power Company
Comparison of Depreciation Rates and Annual Accrual Amounts

Account	Description	12/31/14 Investment	Current Approved Rate	Current Approved Annual Accrual	TEP Proposed Rate	TEP Proposed Annual Accrual	TEP Proposed Difference from Current	Staff Proposed Rate	Staff Proposed Annual Accrual	Staff Proposed Difference from Current	Difference from Company
		A	B	C=A*B	D	E=A*D	F=E-C	G	H=A*G	I=H-C	J=H-E
343.00	Prime Movers	141,618	3.70%	5,238	1.83%	2,591	(2,647)	1.61%	2,273	(2,965)	(318)
344.00	Generators and Devices	8,382,044	0.16%	13,012	-0.39%	(32,333)	(45,345)	-0.32%	(26,897)	(39,909)	5,436
345.00	Accessory Electric Equipment	1,078,811	1.39%	15,027	0.17%	1,800	(13,227)	0.12%	1,313	(13,714)	(487)
346.00	Miscellaneous Power Plant Equipment	49,750	0.00%	0	-1.27%	(633)	(633)	-1.09%	(542)	(542)	91
Total Sundt Gas		**10,451,649**	**0.97%**	**101,538**	**0.01%**	**695**	**(100,843)**	**0.00%**	**(409)**	**(101,947)**	**(1,104)**
Sundt Gas Unit 1											
341.00	Structures and Improvements	5,545	0.10%	6	-0.09%	(5)	(11)	-0.03%	(2)	(8)	3
342.00	Fuel Holders, Products and Accessories	394,168	8.56%	33,741	3.74%	14,742	(18,999)	2.99%	11,786	(21,955)	(2,956)
343.00	Prime Movers	70,809	3.57%	2,527	1.87%	1,324	(1,203)	1.63%	1,154	(1,373)	(170)
344.00	Generators and Devices	4,315,668	0.00%	0	-0.41%	(17,694)	(17,694)	-0.35%	(15,105)	(15,105)	2,589
345.00	Accessory Electric Equipment	516,231	1.08%	5,575	0.12%	619	(4,956)	0.08%	413	(5,162)	(206)
346.00	Miscellaneous Power Plant Equipment	19,906	0.00%	0	-1.23%	(245)	(245)	-1.06%	(211)	(211)	34
Total Sundt Gas Unit 1		**5,322,327**	**0.79%**	**41,849**	**-0.02%**	**(1,259)**	**(43,108)**	**-0.04%**	**(1,965)**	**(43,814)**	**(706)**
Sundt Gas Unit 2											
341.00	Structures and Improvements	5,545	0.42%	24	-0.19%	(11)	(35)	-0.12%	(7)	(31)	4
342.00	Fuel Holders, Products and Accessories	394,168	8.75%	34,490	3.69%	14,544	(19,946)	2.96%	11,667	(22,823)	(2,877)
343.00	Prime Movers	70,809	3.83%	2,711	1.79%	1,267	(1,444)	1.58%	1,119	(1,592)	(148)
344.00	Generators and Devices	4,066,376	0.32%	13,012	-0.36%	(14,639)	(27,651)	-0.29%	(11,792)	(24,804)	2,847
345.00	Accessory Electric Equipment	562,580	1.68%	9,452	0.21%	1,181	(8,271)	0.16%	900	(8,552)	(281)
346.00	Miscellaneous Power Plant Equipment	29,844	0.00%	0	-1.30%	(388)	(388)	-1.11%	(331)	(331)	57
Total Sundt Gas Unit 2		**5,129,322**	**1.16%**	**59,689**	**0.04%**	**1,954**	**(57,735)**	**0.03%**	**1,556**	**(58,133)**	**(398)**

Tucson Electric Power Company
Comparison of Two-Part Depreciation Annual Accrual

Account	Description	12/31/14 Investment	Current Approved Accrual Amount Plant	Current Approved Accrual Amount Net Salvage	Current Approved Accrual Amount Total	TEP Proposed Accrual Amount Plant	TEP Proposed Accrual Amount Net Salvage	TEP Proposed Accrual Amount Total	Difference from Current	Staff Proposed Accrual Amount Plant	Staff Proposed Accrual Amount Net Salvage	Staff Proposed Accrual Amount Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
STEAM PRODUCTION														
310.00	Rights-of-Way	5,106,662	154,751	2	154,753	145,417	5	145,422	(9,331)	134,879	5	134,884	(19,869)	(10,538)
311.00	Structures and Improvements	205,277,689	6,925,225	672,414	7,597,639	6,508,604	1,383,704	7,892,308	294,669	6,248,749	1,001,331	7,250,080	(347,559)	(642,228)
312.00	Boiler Plant Equipment	1,091,953,161	31,609,169	4,124,981	35,734,150	33,091,364	5,676,033	38,767,397	3,033,247	32,105,574	3,584,688	35,690,262	(43,888)	(3,077,135)
314.00	Turbogenerator Units	303,041,923	9,895,445	2,168,057	12,063,502	9,960,460	1,660,521	11,620,981	(442,521)	9,643,080	1,119,959	10,763,039	(1,300,463)	(857,942)
315.00	Accessory Electric Equipment	144,581,471	5,383,758	1,355,199	6,738,957	4,437,440	1,015,739	5,453,179	(1,285,778)	4,203,786	663,672	4,867,457	(1,871,500)	(585,722)
316.00	Miscellaneous Power Plant Equipment	25,222,863	842,395	101,717	944,112	746,073	105,099	851,172	(92,940)	722,901	72,308	795,209	(148,903)	(55,963)
Total Steam Production Plant		**1,775,183,769**	**54,810,743**	**8,422,370**	**63,233,113**	**54,889,358**	**9,841,101**	**64,730,459**	**1,497,346**	**53,058,969**	**6,441,962**	**59,500,931**	**(3,732,182)**	**(5,229,528)**
OTHER PRODUCTION														
Non-Solar														
341.00	Structures and Improvements	23,403,461	587,238	72,042	659,280	603,985	88,395	692,380	33,100	596,697	44,931	641,628	(17,652)	(50,752)
342.00	Fuel Holders, Products and Accessories	19,977,187	541,762	62,185	603,947	530,626	75,123	605,749	1,802	521,383	38,449	559,832	(44,115)	(45,917)
343.00	Prime Movers	202,005,134	4,774,207	83,405	4,857,612	5,028,029	448,274	5,476,303	618,691	4,943,812	244,057	5,187,869	330,257	(288,434)
344.00	Generators and Devices	105,487,225	2,241,822	156,008	2,397,830	2,059,197	189,494	2,248,691	(149,139)	2,003,583	100,718	2,104,301	(293,529)	(144,390)
345.00	Accessory Electric Equipment	13,809,819	322,600	10,605	333,205	289,354	23,496	312,850	(20,355)	277,172	12,201	289,373	(43,832)	(23,477)
346.00	Miscellaneous Power Plant Equipment	15,307,160	374,821	41,324	416,145	384,096	53,510	437,606	21,461	379,374	27,355	406,729	(9,416)	(30,877)
Total Non-Solar		**379,989,986**	**8,842,450**	**425,569**	**9,268,019**	**8,895,287**	**878,292**	**9,773,579**	**505,560**	**8,722,021**	**467,711**	**9,189,732**	**(78,287)**	**(583,847)**
Solar														
344.00	Generators and Devices	170,320,932	8,737,463	0	8,737,463	5,856,756	295,265	6,152,021	(2,585,442)	5,856,756	295,265	6,152,021	(2,585,442)	0
Total Solar		**170,320,932**	**9,434,884**	**51,929**	**9,486,813**	**5,856,756**	**295,265**	**6,152,021**	**(3,334,792)**	**5,856,756**	**295,265**	**6,848,122**	**(2,638,691)**	**696,101**
Total Other Production Plant														
DISTRIBUTION PLANT														
360.RW	Rights-of-Way	7,865,073	112,471	0	112,471	110,898	0	110,898	(1,573)	99,886	0	99,886	(12,585)	(11,012)
361.00	Structures and Improvements	11,402,474	196,123	0	196,123	194,982	0	194,982	(1,141)	189,281	0	189,281	(6,842)	(5,701)
362.00	Station Equipment	157,067,530	2,403,133	0	2,403,133	2,607,321	0	2,607,321	204,188	2,481,667	0	2,481,667	78,534	(125,654)
364.00	Poles, Towers and Fixtures	222,006,967	3,862,921	0	3,862,921	3,685,316	0	3,685,316	(177,605)	3,507,710	0	3,507,710	(355,211)	(177,606)
365.00	Overhead Conductors and Devices	175,675,966	2,863,518	0	2,863,518	2,881,086	0	2,881,086	17,568	2,705,410	0	2,705,410	(158,108)	(175,676)
366.00	Underground Conduit	58,725,355	792,792	0	792,792	798,665	0	798,665	5,873	739,939	0	739,939	(52,853)	(58,726)
367.00	Underground Conductors and Devices	297,183,135	5,557,325	0	5,557,325	5,289,860	0	5,289,860	(267,465)	4,903,522	0	4,903,522	(653,803)	(386,338)
368.OH	Line Transformers - Overhead	103,657,922	1,938,403	0	1,938,403	1,814,014	0	1,814,014	(124,389)	1,689,624	0	1,689,624	(248,779)	(124,390)
368.UG	Line Transformers - Underground	172,890,932	3,613,420	0	3,613,420	3,405,951	0	3,405,951	(207,469)	3,163,904	0	3,163,904	(449,516)	(242,047)
369.OH	Services - Overhead	17,542,236	324,531	0	324,531	321,023	0	321,023	(3,508)	291,201	0	291,201	(33,330)	(29,822)
369.UG	Services - Underground	112,947,714	1,716,805	0	1,716,805	1,716,805	0	1,716,805	0	1,626,447	0	1,626,447	(90,358)	(90,358)
370.00	Meters	44,869,823	1,476,217	0	1,476,217	2,068,499	0	2,068,499	592,282	1,992,220	0	1,992,220	516,003	(76,279)
373.00	Street Lighting and Signal Systems	11,778,362	208,477	0	208,477	207,299	0	207,299	(1,178)	190,809	0	190,809	(17,668)	(16,490)
Total Distribution Plant		**1,393,613,489**	**25,066,136**	**0**	**25,066,136**	**25,101,719**	**0**	**25,101,719**	**35,583**	**23,581,622**	**0**	**23,581,622**	**(1,484,514)**	**(1,520,097)**
GENERAL PLANT														
Depreciable														
390.00	Structures and Improvements	135,680,348	3,378,441	203,521	3,581,962	3,432,713	203,521	3,636,234	54,272	3,432,713	203,521	3,636,234	54,272	0
392.C0	Transportation - Class 0	1,238,946	61,452	(9,044)	52,408	63,682	(10,655)	53,027	619	63,682	(10,655)	53,027	619	0
392.C1	Transportation - Class 1	7,718,183	959,370	(139,699)	819,671	1,001,048	(169,800)	831,248	11,577	1,001,048	(169,800)	831,248	11,577	0

Tucson Electric Power Company
Comparison of Two-Part Depreciation Annual Accrual

Account	Description	12/31/14 Investment	Current Approved Accrual Amount Net Plant	Current Approved Accrual Amount Net Salvage	Current Approved Accrual Amount Net Total	TEP Proposed Accrual Amount Net Plant	TEP Proposed Accrual Amount Net Salvage	TEP Proposed Accrual Amount Net Total	Difference from Current	Staff Proposed Accrual Amount Net Plant	Staff Proposed Accrual Amount Net Salvage	Staff Proposed Accrual Amount Net Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
392.C2	Transportation - Class 2	3,839,907	470,389	(68,350)	402,039	494,580	(85,630)	408,950	6,911	494,580	(85,630)	408,950	6,911	0
392.C3	Transportation - Class 3	2,076,936	222,440	(32,400)	190,040	238,640	(41,954)	196,686	6,646	238,640	(41,954)	196,686	6,646	0
392.C4	Transportation - Class 4	2,935,027	206,332	(29,937)	176,395	222,769	(39,623)	183,146	6,751	222,769	(39,623)	183,146	6,751	0
392.C5	Transportation - Class 5	7,982,715	583,536	(86,213)	497,323	628,240	(104,574)	523,666	26,343	628,240	(104,574)	523,666	26,343	0
392.C6	Transportation - Class 6	365,200	24,286	(3,652)	20,634	24,761	(3,689)	21,072	438	24,761	(3,689)	21,072	438	0
392.C7	Transportation - Class 7	1,047,216	73,096	(10,891)	62,205	75,400	(11,310)	64,090	1,885	75,400	(11,310)	64,090	1,885	0
392.C8	Transportation - Class 8	9,957,500	746,813	(112,520)	634,293	781,664	(118,494)	663,170	28,877	781,664	(118,494)	663,170	28,877	0
392.C9	Transportation - Class 9	4,252,286	198,157	(29,766)	168,391	170,942	(25,939)	145,003	(23,388)	170,942	(25,939)	145,003	(23,388)	0
396.00	Power Operatied Equipment	11,860,940	768,589	(28,466)	740,123	797,055	(7,117)	789,938	49,815	797,055	(7,117)	789,938	49,815	0
397.EM	EMS and SCADA Equipment	11,304,371	560,697	0	560,697	578,784	0	578,784	18,087	578,784	0	578,784	18,087	0
	Total Depreciable	**200,259,575**	**8,253,598**	**(347,417)**	**7,906,181**	**8,510,278**	**(415,264)**	**8,095,014**	**188,833**	**8,510,278**	**(415,264)**	**8,095,014**	**188,833**	**0**
	Amortizable													
391.00	Furniture and Office Equipment	23,964,411	993,514	0	993,514	993,514	0	993,514	0	993,514	0	993,514	0	0
391.20	Network and Data Equipment	29,359,636	5,484,102	0	5,484,102	5,484,102	0	5,484,102	0	5,484,102	0	5,484,102	0	0
393.00	Stores Equipment	1,852,479	117,635	0	117,635	117,635	0	117,635	0	117,635	0	117,635	0	0
394.00	Tools, Shop and Garage Equipment	6,934,368	396,576	0	396,576	396,576	0	396,576	0	396,576	0	396,576	0	0
395.00	Laboratory Equipment	5,091,270	294,185	0	294,185	294,185	0	294,185	0	294,185	0	294,185	0	0
397.20	Telecommunications Equipment	57,456,141	3,785,287	0	3,785,287	3,785,287	0	3,785,287	0	3,785,287	0	3,785,287	0	0
398.00	Miscellaneous Equipment	4,348,209	217,244	0	217,244	217,244	0	217,244	0	217,244	0	217,244	0	0
	Total Amortizable	**129,006,514**	**11,288,543**	**0**	**11,288,543**	**11,288,543**	**0**	**11,288,543**	**0**	**11,288,543**	**0**	**11,288,543**	**0**	**0**
	Total General Plant	**329,266,089**	**19,542,141**	**(347,417)**	**19,194,724**	**19,798,821**	**(415,264)**	**19,383,557**	**188,833**	**19,798,821**	**(415,264)**	**19,383,557**	**188,833**	**0**
	SUBTOTAL	**4,048,374,265**	**116,998,933**	**8,500,522**	**125,499,455**	**114,541,941**	**10,599,394**	**125,141,335**	**(358,120)**	**111,018,189**	**6,789,673**	**117,807,862**	**(7,691,593)**	**(7,333,473)**
	NET SALVAGE													
108.02	Distribution	1,393,613,489	0	3,762,756	3,762,756	0	3,484,034	3,484,034	(278,722)	0	1,114,891	1,114,891	(2,647,865)	(2,369,143)
	Total Net Salvage	**1,393,613,489**	**0**	**3,762,756**	**3,762,756**	**0**	**3,484,034**	**3,484,034**	**(278,722)**	**0**	**1,114,891**	**1,114,891**	**(2,647,865)**	**(2,369,143)**
	TOTAL UTILITY	**4,048,374,265**	**116,998,933**	**12,263,278**	**129,262,211**	**114,541,941**	**14,083,428**	**128,625,369**	**(636,842)**	**111,018,189**	**7,904,564**	**118,922,753**	**(10,339,458)**	**(9,702,616)**
	STEAM PRODUCTION (by Unit)													
	Four Corners													
310.00	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0
311.00	Structures and Improvements	2,982,777	65,429	5,210	70,639	73,741	4,461	78,202	7,563	72,097	3,427	75,524	4,885	(2,678)
312.00	Boiler Plant Equipment	76,402,061	1,219,616	111,205	1,330,821	1,202,927	92,246	1,295,173	(35,648)	1,149,446	73,286	1,222,732	(108,089)	(72,441)
314.00	Turbogenerator Units	12,359,480	287,585	16,903	304,488	254,487	12,677	267,164	(37,324)	246,553	8,970	255,523	(48,965)	(11,641)
315.00	Accessory Electric Equipment	4,390,980	153,002	8,523	161,525	177,401	8,702	186,103	24,578	175,856	6,750	182,607	21,082	(3,496)
316.00	Miscellaneous Power Plant Equipment	3,832,234	91,767	6,700	98,467	88,687	4,786	93,473	(4,994)	86,387	3,446	89,833	(8,634)	(3,640)
	Total Four Corners	**99,967,532**	**1,817,399**	**148,541**	**1,965,940**	**1,797,243**	**122,872**	**1,920,115**	**(45,825)**	**1,730,339**	**95,880**	**1,826,219**	**(139,721)**	**(93,896)**
	Four Corners Unit 4													
310.00	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0
311.00	Structures and Improvements	1,524,414	32,470	2,439	34,909	35,824	1,982	37,806	2,897	34,909	1,677	36,586	1,677	(1,220)
312.00	Boiler Plant Equipment	39,609,538	594,143	63,375	657,518	566,416	55,453	621,869	(35,649)	538,690	47,531	586,221	(71,297)	(35,648)

Tucson Electric Power Company
Comparison of Two-Part Depreciation Annual Accrual

Account	Description	12/31/14 Investment	Current Approved Accrual Amount Net Plant	Net Salvage	Total	TEP Proposed Accrual Amount Net Plant	Net Salvage	Total	Difference from Current	Staff Proposed Accrual Amount Net Plant	Net Salvage	Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
314.00	Turbogenerator Units	7,179,362	175,176	8,615	183,791	149,331	6,461	155,792	(27,999)	145,023	4,308	149,331	(34,460)	(6,461)
315.00	Accessory Electric Equipment	2,274,836	88,036	3,867	91,903	88,946	3,412	92,358	455	88,036	2,730	90,766	(1,137)	(1,592)
316.00	Miscellaneous Power Plant Equipment	1,929,161	45,142	2,894	48,036	42,442	2,122	44,564	(3,472)	41,284	1,543	42,827	(5,209)	(1,737)
Total Four Corners Unit 4		**52,517,311**	**934,967**	**81,190**	**1,016,157**	**882,959**	**69,430**	**952,389**	**(63,768)**	**847,942**	**57,789**	**905,731**	**(110,426)**	**(46,658)**
Four Corners Unit 5														
310.00	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0
311.00	Structures and Improvements	1,458,363	32,959	2,771	35,730	37,917	2,479	40,396	4,666	37,188	1,750	38,938	3,208	(1,458)
312.00	Boiler Plant Equipment	36,792,523	625,473	47,830	673,303	636,511	36,793	673,304	1	610,756	25,755	636,511	(36,792)	(36,793)
314.00	Turbogenerator Units	5,180,118	112,409	8,288	120,697	105,156	6,216	111,372	(9,325)	101,530	4,662	106,192	(14,505)	(5,180)
315.00	Accessory Electric Equipment	2,116,144	64,966	4,656	69,622	88,455	5,290	93,745	24,123	87,820	4,021	91,841	22,219	(1,904)
316.00	Miscellaneous Power Plant Equipment	1,903,073	46,625	3,806	50,431	46,245	2,664	48,909	(1,522)	45,103	1,903	47,006	(3,425)	(1,903)
Total Four Corners Unit 5		**47,450,221**	**882,432**	**67,351**	**949,783**	**914,284**	**53,442**	**967,726**	**17,943**	**882,397**	**38,091**	**920,488**	**(29,295)**	**(47,238)**
Navajo														
310.00	Rights-of-Way	12,229	35	2	37	94	5	99	62	84	5	89	52	(10)
311.00	Structures and Improvements	18,655,156	266,935	19,407	286,342	479,050	27,179	506,229	219,887	468,945	23,276	492,221	205,879	(14,008)
312.00	Boiler Plant Equipment	88,544,201	1,470,251	90,473	1,560,724	2,789,739	144,143	2,933,882	1,373,158	2,745,446	122,428	2,867,875	1,307,151	(66,007)
314.00	Turbogenerator Units	20,255,526	305,780	19,622	325,402	642,358	32,069	674,427	349,025	630,353	28,542	658,895	333,493	(15,532)
315.00	Accessory Electric Equipment	14,829,858	277,041	19,470	296,511	576,222	31,388	607,610	311,099	569,278	26,756	596,035	299,524	(11,575)
316.00	Miscellaneous Power Plant Equipment	4,518,597	71,350	4,862	76,212	128,777	7,365	136,142	59,930	126,599	5,904	132,503	56,291	(3,639)
Total Navajo		**146,815,567**	**2,391,392**	**153,836**	**2,545,228**	**4,616,240**	**242,149**	**4,858,389**	**2,313,161**	**4,540,706**	**206,912**	**4,747,618**	**2,202,390**	**(110,771)**
Navajo Unit 1														
310.00	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0
311.00	Structures and Improvements	3,190,563	22,015	1,595	23,610	131,770	6,381	138,151	114,541	130,494	6,381	136,875	113,265	(1,276)
312.00	Boiler Plant Equipment	27,198,582	475,975	32,638	508,613	1,631,915	81,596	1,713,511	1,204,898	1,623,755	78,876	1,702,631	1,194,018	(10,880)
314.00	Turbogenerator Units	6,860,989	108,404	6,175	114,579	414,404	19,211	433,615	319,036	411,659	18,525	430,184	315,605	(3,431)
315.00	Accessory Electric Equipment	3,544,300	53,519	3,190	56,709	300,557	14,177	314,734	258,025	299,493	13,823	313,316	256,607	(1,418)
316.00	Miscellaneous Power Plant Equipment	471,227	3,157	236	3,393	18,896	895	19,791	16,398	18,708	895	19,603	16,210	(188)
Total Navajo Unit 1		**41,265,661**	**663,070**	**43,834**	**706,904**	**2,497,542**	**122,260**	**2,619,802**	**1,912,898**	**2,484,110**	**118,500**	**2,602,610**	**1,895,706**	**(17,192)**
Navajo Unit 2														
310.00	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0
311.00	Structures and Improvements	1,802,685	17,847	1,262	19,109	25,598	1,622	27,220	8,111	24,336	1,082	25,418	6,309	(1,802)
312.00	Boiler Plant Equipment	26,882,286	408,611	24,194	432,805	456,999	26,882	483,881	51,076	440,869	16,129	456,999	24,194	(26,882)
314.00	Turbogenerator Units	6,926,050	110,817	8,311	119,128	126,054	8,311	134,365	15,237	121,206	6,233	127,439	8,311	(6,926)
315.00	Accessory Electric Equipment	3,172,330	51,392	3,490	54,882	65,033	4,124	69,157	14,275	63,129	3,172	66,302	11,420	(2,855)
316.00	Miscellaneous Power Plant Equipment	515,874	4,540	310	4,850	5,004	310	5,314	464	4,591	206	4,798	(52)	(516)
Total Navajo Unit 2		**39,299,225**	**593,207**	**37,567**	**630,774**	**678,688**	**41,249**	**719,937**	**89,163**	**654,132**	**26,823**	**680,955**	**50,181**	**(38,982)**
Navajo Unit 3														
310.00	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0
311.00	Structures and Improvements	3,681,511	36,447	2,577	39,024	41,233	2,209	43,442	4,418	38,656	1,841	40,497	1,473	(2,945)
312.00	Boiler Plant Equipment	27,718,514	437,953	22,175	460,128	507,249	22,175	529,424	69,296	490,618	16,631	507,249	47,121	(22,175)
314.00	Turbogenerator Units	6,178,944	75,383	4,325	79,708	87,741	3,707	91,448	11,740	83,416	3,089	86,505	6,797	(4,943)

Tucson Electric Power Company
Comparison of Two-Part Depreciation Annual Accrual

Account	Description	12/31/14 Investment	Current Approved Accrual Amount Net Plant	Current Approved Accrual Amount Net Salvage	Current Approved Accrual Amount Total	TEP Proposed Accrual Amount Net Plant	TEP Proposed Accrual Amount Net Salvage	TEP Proposed Accrual Amount Total	Difference from Current	Staff Proposed Accrual Amount Net Plant	Staff Proposed Accrual Amount Net Salvage	Staff Proposed Accrual Amount Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
315.00	Accessory Electric Equipment	5,139,872	68,360	5,654	74,014	80,696	5,654	86,350	12,336	77,612	4,112	81,724	7,710	(4,626)
316.00	Miscellaneous Power Plant Equipment	549,362	4,010	439	4,449	5,274	494	5,768	1,319	4,889	330	5,219	770	(549)
Total Navajo Unit 3		**43,268,203**	**622,153**	**35,170**	**657,323**	**722,193**	**34,239**	**756,432**	**99,109**	**695,191**	**26,003**	**721,194**	**63,871**	**(35,238)**
Navajo Common														
310.00	Rights-of-Way	12,229	35	2	37	94	5	99	62	84	5	89	52	(10)
311.00	Structures and Improvements	9,980,397	190,626	13,973	204,599	280,449	16,967	297,416	92,817	275,459	13,973	289,432	84,833	(7,984)
312.00	Boiler Plant Equipment	6,744,819	147,712	11,466	159,178	193,576	13,490	207,066	47,888	190,204	10,792	200,996	41,818	(6,070)
314.00	Turbogenerator Units	289,543	11,176	811	11,987	14,159	840	14,999	3,012	14,072	695	14,767	2,780	(232)
315.00	Accessory Electric Equipment	2,973,356	103,770	7,136	110,906	129,936	7,433	137,369	26,463	129,044	5,649	134,693	23,787	(2,676)
316.00	Miscellaneous Power Plant Equipment	2,982,134	59,643	3,877	63,520	99,603	5,666	105,269	41,749	98,410	4,473	102,884	39,364	(2,385)
Total Navajo Common		**22,982,478**	**512,962**	**37,265**	**550,227**	**717,817**	**44,401**	**762,218**	**211,991**	**707,273**	**35,587**	**742,860**	**192,633**	**(19,358)**
San Juan														
310.00	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0
311.00	Structures and Improvements	14,437,744	248,228	21,674	269,902	1,093,818	104,193	1,198,011	928,109	1,092,391	85,644	1,178,035	908,133	(19,976)
312.00	Boiler Plant Equipment	154,506,908	3,788,408	1,148,165	4,936,573	11,797,736	1,386,578	13,184,314	8,247,741	11,782,286	1,142,228	12,924,514	7,987,941	(259,800)
314.00	Turbogenerator Units	44,295,673	912,491	79,732	992,223	3,357,612	323,358	3,680,970	2,688,747	3,353,182	265,774	3,618,956	2,626,733	(62,014)
315.00	Accessory Electric Equipment	10,063,526	210,328	19,121	229,449	767,847	73,464	841,311	611,862	766,841	60,381	827,222	597,773	(14,089)
316.00	Miscellaneous Power Plant Equipment	2,009,555	31,839	2,411	34,250	152,968	14,113	167,081	132,831	152,772	11,565	164,337	130,087	(2,744)
Total San Juan		**225,313,406**	**5,191,294**	**1,271,103**	**6,462,397**	**17,169,981**	**1,901,706**	**19,071,687**	**12,609,290**	**17,147,472**	**1,565,598**	**18,713,065**	**12,250,668**	**(358,622)**
San Juan Unit 1														
310.00	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0
311.00	Structures and Improvements	14,268,404	245,417	21,403	266,820	1,080,118	104,159	1,184,277	917,457	1,078,691	85,610	1,164,302	897,482	(19,975)
312.00	Boiler Plant Equipment	146,453,029	3,485,582	366,133	3,851,715	11,174,366	1,083,752	12,258,118	8,406,403	11,159,721	893,363	12,053,084	8,201,369	(205,034)
314.00	Turbogenerator Units	44,295,673	912,491	79,732	992,223	3,357,612	323,358	3,680,970	2,688,747	3,353,182	265,774	3,618,956	2,626,733	(62,014)
315.00	Accessory Electric Equipment	10,063,526	210,328	19,121	229,449	767,847	73,464	841,311	611,862	766,841	60,381	827,222	597,773	(14,089)
316.00	Miscellaneous Power Plant Equipment	1,960,172	31,167	2,352	33,519	148,973	14,113	163,086	129,567	148,777	11,565	160,342	126,823	(2,744)
Total San Juan Unit 1		**217,040,804**	**4,884,985**	**488,741**	**5,373,726**	**16,528,916**	**1,598,846**	**18,127,762**	**12,754,036**	**16,507,212**	**1,316,694**	**17,823,906**	**12,450,180**	**(303,856)**
San Juan Common														
310.00	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0
311.00	Structures and Improvements	169,340	2,811	271	3,082	13,700	34	13,734	10,652	13,700	34	13,733	10,651	(1)
312.00	Boiler Plant Equipment	8,053,879	302,826	782,032	1,084,858	623,370	302,826	926,196	(158,662)	622,565	248,865	871,430	(213,428)	(54,766)
314.00	Turbogenerator Units	0	0	0	0	0	0	0	0	0	0	0	0	0
315.00	Accessory Electric Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0
316.00	Miscellaneous Power Plant Equipment	49,383	672	59	731	3,995	0	3,995	3,264	3,995	0	3,995	3,264	0
Total San Juan Common		**8,272,602**	**306,309**	**782,362**	**1,088,671**	**641,065**	**302,860**	**943,925**	**(144,746)**	**640,260**	**248,899**	**889,158**	**(199,513)**	**(54,767)**
Springerville														
310.00	Rights-of-Way	5,094,433	154,716	0	154,716	145,323	0	145,323	(9,393)	134,795	0	134,795	(19,921)	(10,528)
311.00	Structures and Improvements	141,726,641	5,270,099	65,329	5,335,428	4,028,521	849,209	4,877,730	(457,698)	3,882,896	650,632	4,533,528	(801,900)	(344,202)
312.00	Boiler Plant Equipment	641,687,365	20,250,799	469,997	20,720,796	13,625,822	2,489,675	16,115,497	(4,605,299)	13,155,201	1,324,484	14,479,685	(6,241,111)	(1,635,812)
314.00	Turbogenerator Units	173,649,915	5,159,622	146,103	5,305,725	3,783,448	240,492	4,023,940	(1,281,785)	3,723,773	155,623	3,879,396	(1,426,329)	(144,544)
315.00	Accessory Electric Equipment	75,864,618	2,506,161	57,172	2,563,333	1,444,701	138,955	1,583,656	(979,677)	1,393,448	90,179	1,483,627	(1,079,706)	(100,029)

Tucson Electric Power Company
Comparison of Two-Part Depreciation Annual Accrual

Account	Description	12/31/14 Investment	Current Approved Accrual Amount Plant	Net Salvage	Total	TEP Proposed Accrual Amount Plant	Net Salvage	Total	Difference from Current	Staff Proposed Accrual Amount Plant	Net Salvage	Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
316.00	Miscellaneous Power Plant Equipment	12,528,984	500,165	7,287	507,452	282,408	29,809	312,217	(195,235)	274,826	20,102	294,928	(212,524)	(17,289)
Total Springerville		**1,050,551,956**	**33,841,562**	**745,888**	**34,587,450**	**23,310,223**	**3,748,140**	**27,058,363**	**(7,529,087)**	**22,564,940**	**2,241,020**	**24,805,960**	**(9,781,490)**	**(2,252,403)**
Springerville Unit 1														
310.00	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0
311.00	Structures and Improvements	20,076,015	1,600,058	2,008	1,602,066	413,566	16,061	429,627	(1,172,439)	405,536	10,038	415,574	(1,186,492)	(14,053)
312.00	Boiler Plant Equipment	185,682,490	11,419,473	55,705	11,475,178	3,676,513	148,546	3,825,059	(7,650,119)	3,602,240	74,273	3,676,513	(7,798,665)	(148,546)
314.00	Turbogenerator Units	49,547,312	2,858,880	(24,774)	2,834,106	976,082	39,638	1,015,720	(1,818,386)	956,263	19,819	976,082	(1,858,024)	(39,638)
315.00	Accessory Electric Equipment	21,214,167	1,289,821	2,121	1,291,942	367,005	16,971	383,976	(907,966)	356,398	10,607	367,005	(924,937)	(16,971)
316.00	Miscellaneous Power Plant Equipment	3,277,742	284,836	0	284,836	70,144	2,294	72,438	(212,398)	69,160	1,311	70,471	(214,365)	(1,967)
Total Springerville Unit 1		**279,797,726**	**17,453,068**	**35,060**	**17,488,128**	**5,503,310**	**223,510**	**5,726,820**	**(11,761,308)**	**5,389,597**	**116,048**	**5,505,645**	**(11,982,483)**	**(221,175)**
Springerville Unit 1 Common														
310.00	Rights-of-Way	1,143,496	0	0	0	23,213	0	23,213	23,213	21,955	0	21,955	21,955	(1,258)
311.00	Structures and Improvements	52,492,826	1,574,785	5,249	1,580,034	1,070,854	125,983	1,196,837	(383,197)	1,013,112	62,991	1,076,103	(503,931)	(120,734)
312.00	Boiler Plant Equipment	14,854,799	629,843	0	629,843	297,096	38,622	335,718	(294,125)	279,270	20,797	300,067	(329,776)	(35,651)
314.00	Turbogenerator Units	1,264,322	23,137	0	23,137	24,401	3,287	27,688	4,551	22,884	1,770	24,654	1,517	(3,034)
315.00	Accessory Electric Equipment	9,627,097	418,779	0	418,779	174,250	28,881	203,131	(215,648)	161,735	15,403	177,139	(241,640)	(25,992)
316.00	Miscellaneous Power Plant Equipment	1,959,012	72,875	0	72,875	35,850	5,485	41,335	(31,540)	33,303	2,939	36,242	(36,633)	(5,093)
Total Springerville Unit 1 Common		**81,341,552**	**2,719,419**	**5,249**	**2,724,668**	**1,625,664**	**202,258**	**1,827,922**	**(896,746)**	**1,532,260**	**103,900**	**1,636,160**	**(1,088,508)**	**(191,762)**
Springerville Unit 2														
310.00	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0
311.00	Structures and Improvements	36,540,030	679,645	54,810	734,455	789,265	54,810	844,075	109,620	774,649	32,886	807,535	73,080	(36,540)
312.00	Boiler Plant Equipment	295,922,545	5,563,344	414,292	5,977,636	6,273,558	443,884	6,717,442	739,806	6,155,189	295,923	6,451,111	473,475	(266,331)
314.00	Turbogenerator Units	122,055,348	2,245,818	170,877	2,416,695	2,746,245	183,083	2,929,328	512,633	2,709,629	122,055	2,831,684	414,989	(97,644)
315.00	Accessory Electric Equipment	42,346,939	715,663	55,051	770,714	796,122	50,816	846,938	76,224	774,949	29,643	804,592	33,878	(42,346)
316.00	Miscellaneous Power Plant Equipment	6,624,669	113,282	7,287	120,569	141,768	8,612	150,380	29,811	139,118	4,637	143,755	23,186	(6,625)
Total Springerville Unit 2		**503,489,531**	**9,317,752**	**702,317**	**10,020,069**	**10,746,958**	**741,205**	**11,488,163**	**1,468,094**	**10,553,533**	**485,144**	**11,038,677**	**1,018,608**	**(449,486)**
Springerville Unit 2 Common (Leasehold Imp.)														
310.00	Rights-of-Way	2,280,838	63,863	0	63,863	88,040	0	88,040	24,177	82,110	0	82,110	18,247	(5,930)
311.00	Structures and Improvements	32,617,770	1,415,611	3,262	1,418,873	1,754,836	652,355	2,407,191	988,318	1,689,600	544,717	2,234,317	815,444	(172,874)
312.00	Boiler Plant Equipment	6,282,729	345,550	0	345,550	405,236	135,707	540,943	195,393	395,184	113,717	508,901	163,351	(32,042)
314.00	Turbogenerator Units	782,933	31,787	0	31,787	36,720	14,484	51,204	19,417	34,997	11,979	46,976	15,189	(4,228)
315.00	Accessory Electric Equipment	2,676,415	81,898	0	81,898	107,324	42,287	149,611	67,713	100,366	34,526	134,891	52,993	(14,720)
316.00	Miscellaneous Power Plant Equipment	667,561	29,172	0	29,172	34,646	13,418	48,064	18,892	33,245	11,215	44,460	15,288	(3,604)
Total Springerville Unit 2 Common		**45,308,246**	**1,967,881**	**3,262**	**1,971,143**	**2,426,802**	**858,251**	**3,285,053**	**1,313,910**	**2,335,502**	**716,154**	**3,051,655**	**1,080,512**	**(233,398)**
Springerville Coal Handling														
310.00	Rights-of-Way	1,670,099	90,853	0	90,853	34,070	0	34,070	(56,783)	30,730	0	30,730	(60,123)	(3,340)
311.00	Structures and Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0
312.00	Boiler Plant Equipment	138,944,802	2,292,589	0	2,292,589	2,973,419	1,722,916	4,696,335	2,403,746	2,723,318	819,774	3,543,092	1,250,503	(1,153,243)
314.00	Turbogenerator Units	0	0	0	0	0	0	0	0	0	0	0	0	0
315.00	Accessory Electric Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0
316.00	Miscellaneous Power Plant Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0

Tucson Electric Power Company
Comparison of Two-Part Depreciation Annual Accrual

Account	Description	12/31/14 Investment	Current Approved Accrual Amount Plant	Current Approved Accrual Amount Net Salvage	Current Approved Accrual Amount Total	TEP Proposed Accrual Amount Plant	TEP Proposed Accrual Amount Net Salvage	TEP Proposed Accrual Amount Total	Difference from Current	Staff Proposed Accrual Amount Plant	Staff Proposed Accrual Amount Net Salvage	Staff Proposed Accrual Amount Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
Total Springerville Coal Handling		**140,614,901**	**2,383,442**	**0**	**2,383,442**	**3,007,489**	**1,722,916**	**4,730,405**	**2,346,963**	**2,754,048**	**819,774**	**3,573,822**	**1,190,380**	**(1,156,583)**
Sundt														
310.00	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0
311.00	Structures and Improvements	27,475,371	1,074,534	560,794	1,635,328	833,474	398,662	1,232,136	(403,192)	732,419	238,351	970,771	(664,557)	(261,365)
312.00	Boiler Plant Equipment	130,812,626	4,880,095	2,305,141	7,185,236	3,675,140	1,563,391	5,238,531	(1,946,705)	3,273,196	922,261	4,195,456	(2,989,780)	(1,043,075)
314.00	Turbogenerator Units	52,481,329	3,229,967	1,905,697	5,135,664	1,922,555	1,051,925	2,974,480	(2,161,184)	1,689,219	661,049	2,350,268	(2,785,396)	(624,212)
315.00	Accessory Electric Equipment	39,432,489	2,237,226	1,250,913	3,488,139	1,471,269	763,230	2,234,499	(1,253,640)	1,298,363	479,605	1,777,967	(1,710,172)	(456,532)
316.00	Miscellaneous Power Plant Equipment	2,333,493	147,274	80,457	227,731	93,233	49,026	142,259	(85,472)	82,317	31,290	113,607	(114,124)	(28,652)
Total Sundt		**252,535,308**	**11,569,096**	**6,103,002**	**17,672,098**	**7,995,671**	**3,826,294**	**11,821,965**	**(5,850,193)**	**7,075,513**	**2,332,557**	**9,408,069**	**(8,264,029)**	**(2,413,836)**
Sundt Unit 1														
310.00	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0
311.00	Structures and Improvements	3,926,062	390,643	210,830	601,473	195,910	108,752	304,662	(296,811)	148,405	64,780	213,185	(388,288)	(91,477)
312.00	Boiler Plant Equipment	13,782,181	1,433,347	691,865	2,125,212	625,711	326,638	952,349	(1,172,863)	476,863	194,329	671,192	(1,454,020)	(281,157)
314.00	Turbogenerator Units	10,237,507	1,195,741	630,630	1,826,371	509,828	277,436	787,264	(1,039,107)	391,073	165,848	556,920	(1,269,451)	(230,344)
315.00	Accessory Electric Equipment	6,536,315	858,872	466,039	1,324,911	401,983	221,581	623,564	(701,347)	313,743	138,570	452,313	(872,598)	(171,251)
316.00	Miscellaneous Power Plant Equipment	490,578	59,801	31,888	91,689	28,552	16,091	44,643	(47,046)	22,174	10,008	32,182	(59,507)	(12,461)
Total Sundt Unit 1		**34,972,643**	**3,938,404**	**2,031,252**	**5,969,656**	**1,761,984**	**950,498**	**2,712,482**	**(3,257,174)**	**1,352,259**	**573,534**	**1,925,793**	**(4,043,863)**	**(786,689)**
Sundt Unit 2														
310.00	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0
311.00	Structures and Improvements	2,812,689	236,266	149,916	386,182	140,634	85,787	226,421	(159,761)	121,227	55,973	177,199	(208,983)	(49,222)
312.00	Boiler Plant Equipment	14,371,609	1,185,658	771,755	1,957,413	586,362	376,536	962,898	(994,515)	490,072	241,443	731,515	(1,225,898)	(231,383)
314.00	Turbogenerator Units	8,451,923	694,748	438,655	1,133,403	330,470	206,227	536,697	(596,706)	272,997	130,160	403,157	(730,246)	(133,540)
315.00	Accessory Electric Equipment	6,205,700	624,914	394,062	1,018,976	348,140	222,164	570,304	(448,672)	305,941	150,178	456,119	(562,857)	(114,185)
316.00	Miscellaneous Power Plant Equipment	383,824	36,732	22,838	59,570	20,573	12,935	33,508	(26,062)	17,963	8,713	26,676	(32,894)	(6,832)
Total Sundt Unit 2		**32,225,745**	**2,778,318**	**1,777,226**	**4,555,544**	**1,426,179**	**903,649**	**2,329,828**	**(2,225,716)**	**1,208,200**	**586,466**	**1,794,666**	**(2,760,878)**	**(535,162)**
Sundt Unit 3														
310.00	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0
311.00	Structures and Improvements	2,762,012	183,398	135,339	318,737	114,071	80,098	194,169	(124,568)	106,890	54,688	161,578	(157,159)	(32,591)
312.00	Boiler Plant Equipment	11,980,831	739,217	559,505	1,298,722	464,856	335,463	800,319	(498,403)	428,914	227,636	656,550	(642,172)	(143,769)
314.00	Turbogenerator Units	14,830,615	1,011,448	754,878	1,766,326	600,640	424,156	1,024,796	(741,530)	560,597	289,197	849,794	(916,532)	(175,002)
315.00	Accessory Electric Equipment	6,140,139	439,020	316,831	755,851	244,378	169,468	413,846	(342,005)	226,571	114,821	341,392	(414,459)	(72,454)
316.00	Miscellaneous Power Plant Equipment	404,717	31,973	22,462	54,435	18,698	12,830	31,528	(22,907)	17,929	8,985	26,914	(27,521)	(4,614)
Total Sundt Unit 3		**36,118,314**	**2,405,056**	**1,789,015**	**4,194,071**	**1,442,643**	**1,022,015**	**2,464,658**	**(1,729,413)**	**1,340,901**	**695,326**	**2,036,227**	**(2,157,844)**	**(428,431)**
Sundt Unit 4														
310.00	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0
311.00	Structures and Improvements	17,974,608	264,227	64,709	328,936	382,859	124,025	506,884	177,948	355,897	62,911	418,808	89,872	(88,076)
312.00	Boiler Plant Equipment	80,576,055	1,184,468	282,016	1,466,484	1,684,040	523,744	2,207,784	741,300	1,563,175	257,843	1,821,019	354,535	(386,765)
314.00	Turbogenerator Units	18,961,284	328,030	81,534	409,564	481,617	144,106	625,723	216,159	464,551	75,845	540,397	130,833	(85,326)
315.00	Accessory Electric Equipment	20,550,335	314,420	73,981	388,401	476,768	150,017	626,785	238,384	452,107	76,036	528,144	139,743	(98,641)
316.00	Miscellaneous Power Plant Equipment	1,054,374	18,768	3,269	22,037	25,410	7,170	32,580	10,543	24,251	3,585	27,835	5,798	(4,745)
Total Sundt Unit 4		**139,116,656**	**2,109,913**	**505,509**	**2,615,422**	**3,050,694**	**949,062**	**3,999,756**	**1,384,334**	**2,859,982**	**476,221**	**3,336,203**	**720,781**	**(663,553)**

Tucson Electric Power Company
Comparison of Two-Part Depreciation Annual Accrual

Account	Description	12/31/14 Investment	Current Approved Accrual Amount Net Plant	Current Approved Accrual Amount Net Salvage	Current Approved Accrual Amount Total	TEP Proposed Accrual Amount Net Plant	TEP Proposed Accrual Amount Net Salvage	TEP Proposed Accrual Amount Total	Difference from Current	Staff Proposed Accrual Amount Net Plant	Staff Proposed Accrual Amount Net Salvage	Staff Proposed Accrual Amount Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
Sundt Solar Booster (Areva)														
310.00	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0
311.00	Structures and Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0
312.00	Boiler Plant Equipment	10,101,950	337,405	0	337,405	314,171	1,010	315,181	(22,224)	314,171	1,010	315,181	(22,224)	0
314.00	Turbogenerator Units	0	0	0	0	0	0	0	0	0	0	0	0	0
315.00	Accessory Electric Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0
316.00	Miscellaneous Power Plant Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total Sundt Solar Booster (Areva)	**10,101,950**	**337,405**	**0**	**337,405**	**314,171**	**1,010**	**315,181**	**(22,224)**	**314,171**	**1,010**	**315,181**	**(22,224)**	**0**
OTHER PRODUCTION (by Unit)														
DeMoss Petrie Gas Unit 1														
341.00	Structures and Improvements	761,988	18,745	1,448	20,193	20,116	1,372	21,488	1,295	19,888	762	20,650	457	(838)
342.00	Fuel Holders, Products and Accessories	750,386	17,259	1,576	18,835	16,734	1,501	18,235	(600)	16,358	825	17,184	(1,651)	(1,051)
343.00	Prime Movers	76,766	2,226	207	2,433	2,196	8	2,204	(229)	2,180	0	2,180	(253)	(24)
344.00	Generators and Devices	30,772,866	707,776	64,623	772,399	689,312	58,468	747,780	(24,619)	673,926	33,850	707,776	(64,623)	(40,004)
345.00	Accessory Electric Equipment	861,492	19,814	1,809	21,623	19,728	431	20,159	(1,464)	19,297	258	19,556	(2,067)	(603)
346.00	Miscellaneous Power Plant Equipment	376,605	8,963	829	9,792	8,888	791	9,679	(113)	8,737	414	9,152	(640)	(527)
	Total DeMoss Petrie Gas Unit 1	**33,600,103**	**774,783**	**70,492**	**845,275**	**756,974**	**62,571**	**819,545**	**(25,730)**	**740,387**	**36,110**	**776,497**	**(68,778)**	**(43,048)**
Gila River														
341.00	Structures and Improvements	8,508,950	192,303	0	192,303	205,534	17,018	222,552	30,249	203,077	9,264	212,341	20,038	(10,211)
342.00	Fuel Holders, Products and Accessories	6,783,045	153,296	0	153,296	162,882	13,566	176,448	23,152	160,847	7,461	168,309	15,013	(8,139)
343.00	Prime Movers	188,744,730	4,265,631	0	4,265,631	4,597,974	378,924	4,976,898	711,267	4,542,785	207,619	4,750,404	484,773	(226,494)
344.00	Generators and Devices	32,783,434	740,906	0	740,906	776,967	65,567	842,534	101,628	767,132	36,062	803,194	62,288	(39,340)
345.00	Accessory Electric Equipment	9,030,698	204,094	0	204,094	215,581	18,061	233,642	29,548	213,559	9,248	222,806	18,712	(10,836)
346.00	Miscellaneous Power Plant Equipment	6,799,960	153,679	0	153,679	163,879	13,600	177,479	23,800	161,839	7,480	169,319	15,640	(8,160)
	Total Gila River	**252,650,817**	**5,709,909**	**0**	**5,709,909**	**6,122,817**	**506,736**	**6,629,553**	**919,644**	**6,049,239**	**277,134**	**6,326,373**	**616,464**	**(303,180)**
Gila River Unit 3														
341.00	Structures and Improvements	957,417	21,638	0	21,638	22,787	1,915	24,702	3,064	22,595	957	23,552	1,914	(1,150)
342.00	Fuel Holders, Products and Accessories	178,424	4,032	0	4,032	4,371	357	4,728	696	4,318	196	4,514	482	(214)
343.00	Prime Movers	181,571,712	4,103,521	0	4,103,521	4,412,193	363,143	4,775,336	671,815	4,357,721	199,729	4,557,450	453,929	(217,886)
344.00	Generators and Devices	32,783,434	740,906	0	740,906	776,967	65,567	842,534	101,628	767,132	36,062	803,194	62,288	(39,340)
345.00	Accessory Electric Equipment	6,860,554	155,049	0	155,049	163,281	13,721	177,002	21,953	161,909	6,861	168,770	13,721	(8,232)
346.00	Miscellaneous Power Plant Equipment	135,558	3,064	0	3,064	3,267	271	3,538	474	3,226	149	3,375	311	(163)
	Total Gila River Unit 3	**222,487,099**	**5,028,210**	**0**	**5,028,210**	**5,382,866**	**444,974**	**5,827,840**	**799,630**	**5,316,902**	**243,954**	**5,560,856**	**532,646**	**(266,984)**
Gila River Common														
341.00	Structures and Improvements	7,551,533	170,665	0	170,665	182,747	15,103	197,850	27,185	180,482	8,307	188,788	18,123	(9,062)
342.00	Fuel Holders, Products and Accessories	6,604,621	149,264	0	149,264	158,511	13,209	171,720	22,456	156,530	7,265	163,795	14,531	(7,925)
343.00	Prime Movers	7,173,018	162,110	0	162,110	185,781	15,781	201,562	39,452	185,064	7,890	192,954	30,844	(8,608)
344.00	Generators and Devices	0	0	0	0	0	0	0	0	0	0	0	0	0
345.00	Accessory Electric Equipment	2,170,144	49,045	0	49,045	52,300	4,340	56,640	7,595	51,649	2,387	54,037	4,992	(2,603)
346.00	Miscellaneous Power Plant Equipment	6,664,402	150,615	0	150,615	160,612	13,329	173,941	23,326	158,613	7,331	165,944	15,329	(7,997)

Tucson Electric Power Company
Comparison of Two-Part Depreciation Annual Accrual

Account	Description	12/31/14 Investment	Current Approved Accrual Amount Plant	Net Salvage	Total	TEP Proposed Accrual Amount Plant	Net Salvage	Total	Difference from Current	Staff Proposed Accrual Amount Plant	Net Salvage	Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
Total Gila River Common		**30,163,718**	**681,699**	**0**	**681,699**	**739,951**	**61,762**	**801,713**	**120,014**	**732,337**	**33,180**	**765,517**	**83,818**	**(36,196)**
Luna														
341.00	Structures and Improvements	13,232,832	348,023	67,487	415,510	367,873	68,811	436,684	21,174	366,549	34,405	400,955	(14,555)	(35,729)
342.00	Fuel Holders, Products and Accessories	11,352,383	297,432	59,032	356,464	315,596	59,032	374,628	18,164	314,461	29,516	343,977	(12,487)	(30,651)
343.00	Prime Movers	11,151,074	295,503	56,870	352,373	316,691	56,870	373,561	21,188	315,575	28,993	344,568	(7,805)	(28,993)
344.00	Generators and Devices	9,486,694	249,500	47,433	296,933	265,627	46,485	312,112	15,179	264,679	23,717	288,395	(8,538)	(23,717)
345.00	Accessory Electric Equipment	9,647	248	0	248	276	52	328	80	276	27	303	55	(25)
346.00	Miscellaneous Power Plant Equipment	7,424,592	194,524	38,608	233,132	206,404	38,608	245,012	11,880	205,661	19,304	224,965	(8,167)	(20,047)
Total Luna		**52,657,222**	**1,385,230**	**269,430**	**1,654,660**	**1,472,467**	**269,858**	**1,742,325**	**87,665**	**1,467,202**	**135,962**	**1,603,164**	**(51,496)**	**(139,161)**
North Loop Gas														
341.00	Structures and Improvements	888,601	28,138	3,106	31,244	10,476	1,196	11,672	(19,572)	7,190	501	7,691	(23,553)	(3,981)
342.00	Fuel Holders, Products and Accessories	303,037	6,727	394	7,121	6,758	394	7,152	31	6,697	212	6,909	(212)	(243)
343.00	Prime Movers	1,890,946	205,693	26,244	231,937	108,626	12,423	121,049	(110,888)	81,049	7,395	88,444	(143,493)	(32,605)
344.00	Generators and Devices	24,062,187	530,628	43,952	574,580	357,948	20,650	378,598	(195,982)	323,905	7,927	331,833	(242,747)	(46,765)
345.00	Accessory Electric Equipment	2,829,171	83,689	8,524	92,213	51,917	5,004	56,921	(35,292)	42,727	2,668	45,394	(46,819)	(11,527)
346.00	Miscellaneous Power Plant Equipment	656,253	17,655	1,887	19,542	5,548	521	6,069	(13,473)	3,665	170	3,836	(15,706)	(2,233)
Total North Loop Gas		**30,630,195**	**872,530**	**84,107**	**956,637**	**541,273**	**40,188**	**581,461**	**(375,176)**	**465,233**	**18,873**	**484,107**	**(472,530)**	**(97,354)**
North Loop Gas Unit 1														
341.00	Structures and Improvements	411,070	18,046	2,014	20,060	5,919	822	6,741	(13,319)	4,070	452	4,522	(15,538)	(2,219)
342.00	Fuel Holders, Products and Accessories	0	0	0	0	0	0	0	0	0	0	0	0	0
343.00	Prime Movers	678,545	65,140	7,193	72,333	25,649	3,393	29,042	(43,291)	19,881	2,171	22,053	(50,280)	(6,989)
344.00	Generators and Devices	3,582,271	94,930	10,389	105,319	7,881	358	8,239	(97,080)	(1,791)	(358)	(2,149)	(107,468)	(10,388)
345.00	Accessory Electric Equipment	790,955	32,429	3,559	35,988	11,943	1,503	13,446	(22,542)	8,305	791	9,096	(26,892)	(4,350)
346.00	Miscellaneous Power Plant Equipment	306,369	13,051	1,471	14,522	3,646	490	4,136	(10,386)	2,451	245	2,696	(11,826)	(1,440)
Total North Loop Gas Unit 1		**5,769,210**	**223,596**	**24,626**	**248,222**	**55,038**	**6,566**	**61,604**	**(186,618)**	**32,916**	**3,301**	**36,217**	**(212,005)**	**(25,387)**
North Loop Gas Unit 2														
341.00	Structures and Improvements	196,078	3,882	608	4,490	1,627	294	1,921	(2,569)	882	137	1,020	(3,470)	(901)
342.00	Fuel Holders, Products and Accessories	0	0	0	0	0	0	0	0	0	0	0	0	0
343.00	Prime Movers	263,450	13,963	2,160	16,123	34,960	1,818	36,778	20,655	24,633	764	25,397	9,274	(11,381)
344.00	Generators and Devices	3,239,719	59,935	8,423	68,358	22,678	3,240	25,918	(42,440)	11,663	972	12,635	(55,723)	(13,283)
345.00	Accessory Electric Equipment	504,895	13,531	1,969	15,500	8,836	1,414	10,250	(5,250)	6,059	808	6,867	(8,633)	(3,383)
346.00	Miscellaneous Power Plant Equipment	128,559	1,144	167	1,311	167	26	193	(1,118)	(193)	(26)	(219)	(1,530)	(412)
Total North Loop Gas Unit 2		**4,332,701**	**92,455**	**13,327**	**105,782**	**68,268**	**6,792**	**75,060**	**(30,722)**	**43,044**	**2,655**	**45,699**	**(60,083)**	**(29,361)**
North Loop Gas Unit 3														
341.00	Structures and Improvements	196,078	4,255	569	4,824	941	157	1,098	(3,726)	275	39	314	(4,510)	(784)
342.00	Fuel Holders, Products and Accessories	0	0	0	0	0	0	0	0	0	0	0	0	0
343.00	Prime Movers	948,951	126,590	16,891	143,481	48,017	7,212	55,229	(88,252)	36,535	4,460	40,995	(102,486)	(14,234)
344.00	Generators and Devices	3,030,531	60,308	6,667	66,975	9,092	0	9,092	(57,883)	0	(1,212)	(1,212)	(68,187)	(10,304)
345.00	Accessory Electric Equipment	503,907	14,361	1,864	16,225	7,256	1,058	8,314	(7,911)	4,686	554	5,241	(10,984)	(3,073)
346.00	Miscellaneous Power Plant Equipment	128,559	1,401	193	1,594	(334)	(51)	(385)	(1,979)	(643)	(77)	(720)	(2,314)	(335)
Total North Loop Gas Unit 3		**4,808,026**	**206,915**	**26,184**	**233,099**	**64,972**	**8,376**	**73,348**	**(159,751)**	**40,853**	**3,764**	**44,617**	**(188,482)**	**(28,731)**

Tucson Electric Power Company
Comparison of Two-Part Depreciation Annual Accrual

Account	Description	12/31/14 Investment	Current Approved Accrual Amount Plant	Current Approved Accrual Amount Net Salvage	Current Approved Accrual Amount Total	TEP Proposed Accrual Amount Plant	TEP Proposed Accrual Amount Net Salvage	TEP Proposed Accrual Amount Total	Difference from Current	Staff Proposed Accrual Amount Plant	Staff Proposed Accrual Amount Net Salvage	Staff Proposed Accrual Amount Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
North Loop Gas Unit 4														
341.00	Structures and Improvements	85,375	1,955	(85)	1,870	1,989	(77)	1,912	42	1,964	(128)	1,836	(34)	(76)
342.00	Fuel Holders, Products and Accessories	303,037	6,727	394	7,121	6,758	394	7,152	31	6,697	212	6,909	(212)	(243)
343.00	Prime Movers	0	0	0	0	0	0	0	0	0	0	0	0	0
344.00	Generators and Devices	14,209,666	315,455	18,473	333,928	318,297	17,052	335,349	1,421	314,034	8,526	322,559	(11,369)	(12,790)
345.00	Accessory Electric Equipment	1,029,414	23,368	1,132	24,500	23,882	1,029	24,911	411	23,677	515	24,191	(309)	(720)
346.00	Miscellaneous Power Plant Equipment	92,766	2,059	56	2,115	2,069	56	2,125	10	2,050	28	2,078	(37)	(47)
Total North Loop Gas Unit 4		**15,720,258**	**349,564**	**19,970**	**369,534**	**352,995**	**18,454**	**371,449**	**1,915**	**348,421**	**9,152**	**357,573**	**(11,961)**	**(13,876)**
Solar Units (Generators and Devices)														
344.00	DeMoss Petrie	1,146,081	58,794	0	58,794	34,955	1,719	36,674	(22,120)	34,955	1,719	36,674	(22,120)	0
344.00	Fort Huachuca	36,709,538	1,883,199	0	1,883,199	1,306,860	66,077	1,372,937	(510,262)	1,306,860	66,077	1,372,937	(510,262)	0
344.00	HQ Rooftop	303,184	15,553	0	15,553	10,611	546	11,157	(4,396)	10,611	546	11,157	(4,396)	0
344.00	OH Rooftop	2,594,590	133,102	0	133,102	90,032	4,411	94,443	(38,659)	90,032	4,411	94,443	(38,659)	0
344.00	OH Test Yard	388,459	19,928	0	19,928	12,042	583	12,625	(7,303)	12,042	583	12,625	(7,303)	0
344.00	Prairie Fire	19,036,520	976,573	0	976,573	666,278	34,266	700,544	(276,029)	666,278	34,266	700,544	(276,029)	0
344.00	Springerville Sites 1-3 (Legacy)	28,766,605	1,475,727	0	1,475,727	877,381	43,150	920,531	(555,196)	877,381	43,150	920,531	(555,196)	0
344.00	Springerville Site 4	7,873,874	403,930	0	403,930	270,074	14,173	284,247	(119,683)	270,074	14,173	284,247	(119,683)	0
343.00	Tucson	87,198	4,473	0	4,473	2,267	113	2,380	(2,093)	2,267	113	2,380	(2,093)	0
344.00	U of A Tech Park Site 1	7,723,832	396,233	0	396,233	264,927	13,903	278,830	(117,403)	264,927	13,903	278,830	(117,403)	0
345.00	U of A Tech Park Site 2	19,191,952	984,547	0	984,547	665,961	32,626	698,587	(285,960)	665,961	32,626	698,587	(285,960)	0
346.00	White Mountain	46,499,099	2,385,404	0	2,385,404	1,655,368	83,698	1,739,066	(646,338)	1,655,368	83,698	1,739,066	(646,338)	0
Total Solar Units		**170,320,932**	**8,737,463**	**0**	**8,737,463**	**5,856,756**	**295,265**	**6,152,021**	**(2,585,442)**	**5,856,756**	**295,265**	**6,152,021**	**(2,585,442)**	**0**
Sundt Gas														
341.00	Structures and Improvements	11,090	29	1	30	(14)	(2)	(16)	(46)	(7)	(1)	(8)	(38)	8
342.00	Fuel Holders, Products and Accessories	788,336	67,048	1,183	68,231	28,656	630	29,286	(38,945)	23,019	434	23,453	(44,778)	(5,833)
343.00	Prime Movers	141,618	5,154	84	5,238	2,542	49	2,591	(2,647)	2,223	50	2,273	(2,965)	(318)
344.00	Generators and Devices	8,382,044	13,012	0	13,012	(30,657)	(1,676)	(32,333)	(45,345)	(26,059)	(838)	(26,897)	(39,909)	5,436
345.00	Accessory Electric Equipment	1,078,811	14,755	272	15,027	1,852	(52)	1,800	(13,227)	1,313	0	1,313	(13,714)	(487)
346.00	Miscellaneous Power Plant Equipment	49,750	0	0	0	(623)	(10)	(633)	(633)	(529)	(13)	(542)	(542)	91
Total Sundt Gas		**10,451,649**	**99,998**	**1,540**	**101,538**	**1,756**	**(1,061)**	**695**	**(100,843)**	**(40)**	**(369)**	**(409)**	**(101,947)**	**(1,104)**
Sundt Gas Unit 1														
341.00	Structures and Improvements	5,545	6	0	6	(4)	(1)	(5)	(11)	(2)	0	(2)	(8)	3
342.00	Fuel Holders, Products and Accessories	394,168	33,189	552	33,741	14,427	315	14,742	(18,999)	11,589	197	11,786	(21,955)	(2,956)
343.00	Prime Movers	70,809	2,485	42	2,527	1,296	28	1,324	(1,203)	1,133	21	1,154	(1,373)	(170)
344.00	Generators and Devices	4,315,668	0	0	0	(16,831)	(863)	(17,694)	(17,694)	(14,673)	(432)	(15,105)	(15,105)	2,589
345.00	Accessory Electric Equipment	516,231	5,472	103	5,575	671	(52)	619	(4,956)	413	0	413	(5,162)	(206)
346.00	Miscellaneous Power Plant Equipment	19,906	0	0	0	(241)	(4)	(245)	(245)	(207)	(4)	(211)	(211)	34
Total Sundt Gas Unit 1		**5,322,327**	**41,152**	**697**	**41,849**	**(682)**	**(577)**	**(1,259)**	**(43,108)**	**(1,747)**	**(217)**	**(1,965)**	**(43,814)**	**(706)**
Sundt Gas Unit 2														
341.00	Structures and Improvements	5,545	23	1	24	(10)	(1)	(11)	(35)	(6)	(1)	(7)	(31)	4
342.00	Fuel Holders, Products and Accessories	394,168	33,859	631	34,490	14,229	315	14,544	(19,946)	11,431	237	11,667	(22,823)	(2,877)

Tucson Electric Power Company
Comparison of Two-Part Depreciation Annual Accrual

Account	Description	12/31/14 Investment	Current Approved Accrual Amount Net Plant	Current Approved Accrual Amount Net Salvage	Current Approved Accrual Amount Net Total	TEP Proposed Accrual Amount Net Plant	TEP Proposed Accrual Amount Net Salvage	TEP Proposed Accrual Amount Net Total	Difference from Current	Staff Proposed Accrual Amount Net Plant	Staff Proposed Accrual Amount Net Salvage	Staff Proposed Accrual Amount Net Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
343.00	Prime Movers	70,809	2,669	42	2,711	1,246	21	1,267	(1,444)	1,090	28	1,119	(1,592)	(148)
344.00	Generators and Devices	4,066,376	13,012	0	13,012	(13,826)	(813)	(14,639)	(27,651)	(11,386)	(407)	(11,792)	(24,804)	2,847
345.00	Accessory Electric Equipment	562,580	9,283	169	9,452	1,181	0	1,181	(8,271)	900	0	900	(8,552)	(281)
346.00	Miscellaneous Power Plant Equipment	29,844	0	0	0	(382)	(6)	(388)	(388)	(322)	(9)	(331)	(331)	57
Total Sundt Gas Unit 2		**5,129,322**	**58,846**	**843**	**59,689**	**2,438**	**(484)**	**1,954**	**(57,735)**	**1,708**	**(152)**	**1,556**	**(58,133)**	**(398)**

Tucson Electric Power Company
Comparison of Two-Part Depreciation Rates

Account	Description	12/31/14 Investment	Current Approved Accrual Rate Net Plant	Net Salvage	Total	TEP Proposed Accrual Rate Net Plant	Net Salvage	Total	Difference from Current	Staff Proposed Accrual Rate Net Plant	Net Salvage	Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
STEAM PRODUCTION														
310.00	Rights-of-Way	5,106,662	3.03%	0.00%	3.03%	2.85%	0.00%	2.85%	-0.18%	2.64%	0.00%	2.64%	-0.39%	-0.21%
311.00	Structures and Improvements	205,277,689	3.37%	0.33%	3.70%	3.17%	0.67%	3.84%	0.14%	3.04%	0.49%	3.53%	-0.17%	-0.31%
312.00	Boiler Plant Equipment	1,091,953,161	2.89%	0.38%	3.27%	3.03%	0.52%	3.55%	0.28%	2.94%	0.33%	3.27%	0.00%	-0.28%
314.00	Turbogenerator Units	303,041,923	3.27%	0.72%	3.98%	3.29%	0.54%	3.83%	-0.15%	3.18%	0.37%	3.55%	-0.43%	-0.28%
315.00	Accessory Electric Equipment	144,581,471	3.72%	0.94%	4.66%	3.07%	0.70%	3.77%	-0.89%	2.91%	0.46%	3.37%	-1.29%	-0.40%
316.00	Miscellaneous Power Plant Equipment	25,222,863	3.34%	0.40%	3.74%	2.96%	0.41%	3.37%	-0.37%	2.87%	0.29%	3.15%	-0.59%	-0.22%
Total Steam Production Plant		**1,775,183,769**	**3.09%**	**0.47%**	**3.56%**	**3.09%**	**0.55%**	**3.65%**	**0.08%**	**2.99%**	**0.36%**	**3.35%**	**-0.21%**	**-0.29%**
OTHER PRODUCTION														
Non-Solar														
341.00	Structures and Improvements	23,403,461	2.51%	0.31%	2.82%	2.58%	0.38%	2.96%	0.14%	2.55%	0.19%	2.74%	-0.08%	-0.22%
342.00	Fuel Holders, Products and Accessories	19,977,187	2.71%	0.31%	3.02%	2.66%	0.37%	3.03%	0.01%	2.61%	0.19%	2.80%	-0.22%	-0.23%
343.00	Prime Movers	202,005,134	2.36%	0.04%	2.40%	2.49%	0.22%	2.71%	0.31%	2.45%	0.12%	2.57%	0.16%	-0.14%
344.00	Generators and Devices	105,487,225	2.13%	0.15%	2.27%	1.95%	0.18%	2.13%	-0.14%	1.90%	0.10%	1.99%	-0.28%	-0.14%
345.00	Accessory Electric Equipment	13,809,819	2.34%	0.08%	2.41%	2.10%	0.17%	2.27%	-0.14%	2.01%	0.09%	2.10%	-0.32%	-0.17%
346.00	Miscellaneous Power Plant Equipment	15,307,160	2.45%	0.27%	2.72%	2.51%	0.35%	2.86%	0.14%	2.48%	0.18%	2.66%	-0.06%	-0.20%
Total Non-Solar		**379,989,986**	**2.33%**	**0.11%**	**2.44%**	**2.34%**	**0.23%**	**2.57%**	**0.13%**	**2.30%**	**0.12%**	**2.42%**	**-0.02%**	**-0.15%**
Solar														
344.00	Generators and Devices	170,320,932	5.13%	0.00%	5.13%	3.44%	0.17%	3.61%	-1.52%	3.44%	0.17%	3.61%	-1.52%	0.00%
Total Solar		**170,320,932**	**5.54%**	**0.03%**	**5.57%**	**3.44%**	**0.17%**	**3.61%**	**-1.96%**	**3.44%**	**0.17%**	**4.02%**	**-1.55%**	**0.41%**
Total Other Production Plant		**550,310,918**	**3.19%**	**0.08%**	**3.27%**	**2.68%**	**0.21%**	**2.89%**	**-0.38%**	**2.65%**	**0.14%**	**2.79%**	**-0.48%**	**-0.11%**
DISTRIBUTION PLANT														
360.RW	Rights-of-Way	7,865,073	1.43%	0.00%	1.43%	1.41%	0.00%	1.41%	-0.02%	1.27%	0.00%	1.27%	-0.16%	-0.14%
361.00	Structures and Improvements	11,402,474	1.72%	0.00%	1.72%	1.71%	0.00%	1.71%	-0.01%	1.66%	0.00%	1.66%	-0.06%	-0.05%
362.00	Station Equipment	157,067,530	1.53%	0.00%	1.53%	1.66%	0.00%	1.66%	0.13%	1.58%	0.00%	1.58%	0.05%	-0.08%
364.00	Poles, Towers and Fixtures	222,006,967	1.74%	0.00%	1.74%	1.66%	0.00%	1.66%	-0.08%	1.58%	0.00%	1.58%	-0.16%	-0.08%
365.00	Overhead Conductors and Devices	175,675,966	1.63%	0.00%	1.63%	1.64%	0.00%	1.64%	0.01%	1.54%	0.00%	1.54%	-0.09%	-0.10%
366.00	Underground Conduit	58,725,355	1.35%	0.00%	1.35%	1.36%	0.00%	1.36%	0.01%	1.26%	0.00%	1.26%	-0.09%	-0.10%
367.00	Underground Conductors and Devices	297,183,135	1.87%	0.00%	1.87%	1.78%	0.00%	1.78%	-0.09%	1.65%	0.00%	1.65%	-0.22%	-0.13%
368.OH	Line Transformers - Overhead	103,657,922	1.87%	0.00%	1.87%	1.75%	0.00%	1.75%	-0.12%	1.63%	0.00%	1.63%	-0.24%	-0.12%
368.UG	Line Transformers - Underground	172,890,932	2.09%	0.00%	2.09%	1.97%	0.00%	1.97%	-0.12%	1.83%	0.00%	1.83%	-0.26%	-0.14%
369.OH	Services - Overhead	17,542,236	1.85%	0.00%	1.85%	1.83%	0.00%	1.83%	-0.02%	1.66%	0.00%	1.66%	-0.19%	-0.17%

Tucson Electric Power Company
Comparison of Two-Part Depreciation Rates

Account	Description	12/31/14 Investment	Current Approved Accrual Rate Net Plant	Net Salvage	Total	TEP Proposed Accrual Rate Net Plant	Net Salvage	Total	Difference from Current	Staff Proposed Accrual Rate Net Plant	Net Salvage	Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
369.UG	Services - Underground	112,947,714	1.52%	0.00%	1.52%	1.52%	0.00%	1.52%	0.00%	1.44%	0.00%	1.44%	-0.08%	-0.08%
370.00	Meters	44,869,823	3.29%	0.00%	3.29%	4.61%	0.00%	4.61%	1.32%	4.44%	0.00%	4.44%	1.15%	-0.17%
373.00	Street Lighting and Signal Systems	11,778,362	1.77%	0.00%	1.77%	1.76%	0.00%	1.76%	-0.01%	1.62%	0.00%	1.62%	-0.15%	-0.14%
Total Distribution Plant		**1,393,613,489**	**1.80%**	**0.00%**	**1.80%**	**1.80%**	**0.00%**	**1.80%**	**0.00%**	**1.69%**	**0.00%**	**1.69%**	**-0.11%**	**-0.11%**
GENERAL PLANT														
Depreciable														
390.00	Structures and Improvements	135,680,348	2.49%	0.15%	2.64%	2.53%	0.15%	2.68%	0.04%	2.53%	0.15%	2.68%	0.04%	0.00%
392.C0	Transportation - Class 0	1,238,946	4.96%	-0.73%	4.23%	5.14%	-0.86%	4.28%	0.05%	5.14%	-0.86%	4.28%	0.05%	0.00%
392.C1	Transportation - Class 1	7,718,183	12.43%	-1.81%	10.62%	12.97%	-2.20%	10.77%	0.15%	12.97%	-2.20%	10.77%	0.15%	0.00%
392.C2	Transportation - Class 2	3,839,907	12.25%	-1.78%	10.47%	12.88%	-2.23%	10.65%	0.18%	12.88%	-2.23%	10.65%	0.18%	0.00%
392.C3	Transportation - Class 3	2,076,936	10.71%	-1.56%	9.15%	11.49%	-2.02%	9.47%	0.32%	11.49%	-2.02%	9.47%	0.32%	0.00%
392.C4	Transportation - Class 4	2,935,027	7.03%	-1.02%	6.01%	7.59%	-1.35%	6.24%	0.23%	7.59%	-1.35%	6.24%	0.23%	0.00%
392.C5	Transportation - Class 5	7,982,715	7.31%	-1.08%	6.23%	7.87%	-1.31%	6.56%	0.33%	7.87%	-1.31%	6.56%	0.33%	0.00%
392.C6	Transportation - Class 6	365,200	6.65%	-1.00%	5.65%	6.78%	-1.01%	5.77%	0.12%	6.78%	-1.01%	5.77%	0.12%	0.00%
392.C7	Transportation - Class 7	1,047,216	6.98%	-1.04%	5.94%	7.20%	-1.08%	6.12%	0.18%	7.20%	-1.08%	6.12%	0.18%	0.00%
392.C8	Transportation - Class 8	9,957,500	7.50%	-1.13%	6.37%	7.85%	-1.19%	6.66%	0.29%	7.85%	-1.19%	6.66%	0.29%	0.00%
392.C9	Transportation - Class 9	4,252,286	4.66%	-0.70%	3.96%	4.02%	-0.61%	3.41%	-0.55%	4.02%	-0.61%	3.41%	-0.55%	0.00%
396.00	Power Operatied Equipment	11,860,940	6.48%	-0.24%	6.24%	6.72%	-0.06%	6.66%	0.42%	6.72%	-0.06%	6.66%	0.42%	0.00%
397.EM	EMS and SCADA Equipment	11,304,371	4.96%	0.00%	4.96%	5.12%	0.00%	5.12%	0.16%	5.12%	0.00%	5.12%	0.16%	0.00%
Total Depreciable		**200,259,575**	**4.12%**	**-0.17%**	**3.95%**	**4.25%**	**-0.21%**	**4.04%**	**0.09%**	**4.25%**	**-0.21%**	**4.04%**	**0.09%**	**0.00%**
Amortizable														
391.00	Furniture and Office Equipment	23,964,411	4.15%	0.00%	4.15%	4.15%	0.00%	4.15%	0.00%	4.15%	0.00%	4.15%	0.00%	0.00%
391.20	Network and Data Equipment	29,359,636	18.68%	0.00%	18.68%	18.68%	0.00%	18.68%	0.00%	18.68%	0.00%	18.68%	0.00%	0.00%
393.00	Stores Equipment	1,852,479	6.35%	0.00%	6.35%	6.35%	0.00%	6.35%	0.00%	6.35%	0.00%	6.35%	0.00%	0.00%
394.00	Tools, Shop and Garage Equipment	6,934,368	5.72%	0.00%	5.72%	5.72%	0.00%	5.72%	0.00%	5.72%	0.00%	5.72%	0.00%	0.00%
395.00	Laboratory Equipment	5,091,270	5.78%	0.00%	5.78%	5.78%	0.00%	5.78%	0.00%	5.78%	0.00%	5.78%	0.00%	0.00%
397.20	Telecommunications Equipment	57,456,141	6.59%	0.00%	6.59%	6.59%	0.00%	6.59%	0.00%	6.59%	0.00%	6.59%	0.00%	0.00%
398.00	Miscellaneous Equipment	4,348,209	5.00%	0.00%	5.00%	5.00%	0.00%	5.00%	0.00%	5.00%	0.00%	5.00%	0.00%	0.00%
Total Amortizable		**129,006,514**	**8.75%**	**0.00%**	**8.75%**	**8.75%**	**0.00%**	**8.75%**	**0.00%**	**8.75%**	**0.00%**	**8.75%**	**0.00%**	**0.00%**
Total General Plant		**329,266,089**	**5.94%**	**-0.11%**	**5.83%**	**6.01%**	**-0.13%**	**5.89%**	**0.06%**	**6.01%**	**-0.13%**	**5.89%**	**0.06%**	**0.00%**
SUBTOTAL		**4,048,374,265**	**2.89%**	**0.21%**	**3.10%**	**2.83%**	**0.26%**	**3.09%**	**-0.01%**	**2.74%**	**0.17%**	**2.91%**	**-0.19%**	**-0.18%**

Tucson Electric Power Company
Comparison of Two-Part Depreciation Rates

Account	Description	12/31/14 Investment	Current Approved Accrual Rate Net Plant	Current Approved Accrual Rate Net Salvage	Current Approved Accrual Rate Total	TEP Proposed Accrual Rate Net Plant	TEP Proposed Accrual Rate Net Salvage	TEP Proposed Accrual Rate Total	Difference from Current	Staff Proposed Accrual Rate Net Plant	Staff Proposed Accrual Rate Net Salvage	Staff Proposed Accrual Rate Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
NET SALVAGE														
108.02	Distribution	1,393,613,489	0.00%	0.27%	0.27%	0.00%	0.25%	0.25%	-0.02%	0.00%	0.08%	0.08%	-0.19%	-0.17%
Total Net Salvage		**1,393,613,489**	**0.00%**	**0.27%**	**0.27%**	**0.00%**	**0.25%**	**0.25%**	**-0.02%**	**0.00%**	**0.08%**	**0.08%**	**-0.19%**	**-0.17%**
TOTAL UTILITY		**4,048,374,265**	**2.89%**	**0.30%**	**3.19%**	**2.83%**	**0.35%**	**3.18%**	**-0.02%**	**2.74%**	**0.20%**	**2.94%**	**-0.26%**	**-0.24%**
STEAM PRODUCTION (by Unit)														
Four Corners														
310.00	Rights-of-Way	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	2,982,777	2.19%	0.17%	2.37%	2.47%	0.15%	2.62%	0.25%	2.42%	0.11%	2.53%	0.16%	-0.09%
312.00	Boiler Plant Equipment	76,402,061	1.60%	0.15%	1.74%	1.57%	0.13%	1.70%	-0.04%	1.50%	0.10%	1.60%	-0.14%	-0.10%
314.00	Turbogenerator Units	12,359,480	2.33%	0.14%	2.46%	2.06%	0.10%	2.16%	-0.30%	1.99%	0.07%	2.07%	-0.40%	-0.09%
315.00	Accessory Electric Equipment	4,390,980	3.48%	0.19%	3.68%	4.04%	0.20%	4.24%	0.56%	4.00%	0.15%	4.16%	0.48%	-0.08%
316.00	Miscellaneous Power Plant Equipment	3,832,234	2.39%	0.17%	2.57%	2.31%	0.13%	2.44%	-0.13%	2.25%	0.09%	2.34%	-0.23%	-0.10%
Total Four Corners		**99,967,532**	**1.82%**	**0.15%**	**1.97%**	**1.80%**	**0.12%**	**1.92%**	**-0.05%**	**1.73%**	**0.10%**	**1.83%**	**-0.14%**	**-0.09%**
Four Corners Unit 4														
310.00	Rights-of-Way	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	1,524,414	2.13%	0.16%	2.29%	2.35%	0.13%	2.48%	0.19%	2.29%	0.11%	2.40%	0.11%	-0.08%
312.00	Boiler Plant Equipment	39,609,538	1.50%	0.16%	1.66%	1.43%	0.14%	1.57%	-0.09%	1.36%	0.12%	1.48%	-0.18%	-0.09%
314.00	Turbogenerator Units	7,179,362	2.44%	0.12%	2.56%	2.08%	0.09%	2.17%	-0.39%	2.02%	0.06%	2.08%	-0.48%	-0.09%
315.00	Accessory Electric Equipment	2,274,836	3.87%	0.17%	4.04%	3.91%	0.15%	4.06%	0.02%	3.87%	0.12%	3.99%	-0.05%	-0.07%
316.00	Miscellaneous Power Plant Equipment	1,929,161	2.34%	0.15%	2.49%	2.20%	0.11%	2.31%	-0.18%	2.14%	0.08%	2.22%	-0.27%	-0.09%
Total Four Corners Unit 4		**52,517,311**	**1.78%**	**0.15%**	**1.93%**	**1.68%**	**0.13%**	**1.81%**	**-0.12%**	**1.61%**	**0.11%**	**1.72%**	**-0.21%**	**-0.09%**
		0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Four Corners Unit 5														
310.00	Rights-of-Way	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	1,458,363	2.26%	0.19%	2.45%	2.60%	0.17%	2.77%	0.32%	2.55%	0.12%	2.67%	0.22%	-0.10%
312.00	Boiler Plant Equipment	36,792,523	1.70%	0.13%	1.83%	1.73%	0.10%	1.83%	0.00%	1.66%	0.07%	1.73%	-0.10%	-0.10%
314.00	Turbogenerator Units	5,180,118	2.17%	0.16%	2.33%	2.03%	0.12%	2.15%	-0.18%	1.96%	0.09%	2.05%	-0.28%	-0.10%
315.00	Accessory Electric Equipment	2,116,144	3.07%	0.22%	3.29%	4.18%	0.25%	4.43%	1.14%	4.15%	0.19%	4.34%	1.05%	-0.09%
316.00	Miscellaneous Power Plant Equipment	1,903,073	2.45%	0.20%	2.65%	2.43%	0.14%	2.57%	-0.08%	2.37%	0.10%	2.47%	-0.18%	-0.10%
Total Four Corners Unit 5		**47,450,221**	**1.86%**	**0.14%**	**2.00%**	**1.93%**	**0.11%**	**2.04%**	**0.04%**	**1.86%**	**0.08%**	**1.94%**	**-0.06%**	**-0.10%**
		0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Navajo														
310.00	Rights-of-Way	12,229	0.29%	0.02%	0.30%	0.77%	0.04%	0.81%	0.51%	0.69%	0.04%	0.73%	0.43%	-0.08%

Tucson Electric Power Company
Comparison of Two-Part Depreciation Rates

Account	Description	12/31/14 Investment	Current Approved Accrual Rate Net Plant	Current Approved Accrual Rate Net Salvage	Current Approved Accrual Rate Total	TEP Proposed Accrual Rate Net Plant	TEP Proposed Accrual Rate Net Salvage	TEP Proposed Accrual Rate Total	Difference from Current	Staff Proposed Accrual Rate Net Plant	Staff Proposed Accrual Rate Net Salvage	Staff Proposed Accrual Rate Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
311.00	Structures and Improvements	18,655,156	1.43%	0.10%	1.53%	2.57%	0.14%	2.71%	1.18%	2.51%	0.12%	2.64%	1.10%	-0.07%
312.00	Boiler Plant Equipment	88,544,201	1.66%	0.10%	1.76%	3.15%	0.16%	3.31%	1.55%	3.10%	0.14%	3.24%	1.48%	-0.07%
314.00	Turbogenerator Units	20,255,526	1.51%	0.10%	1.61%	3.17%	0.16%	3.33%	1.72%	3.11%	0.14%	3.25%	1.65%	-0.08%
315.00	Accessory Electric Equipment	14,829,858	1.87%	0.13%	2.00%	3.89%	0.21%	4.10%	2.10%	3.84%	0.18%	4.02%	2.02%	-0.08%
316.00	Miscellaneous Power Plant Equipment	4,518,597	1.58%	0.11%	1.69%	2.85%	0.16%	3.01%	1.32%	2.80%	0.13%	2.93%	1.25%	-0.08%
Total Navajo		**146,815,567**	**1.63%**	**0.10%**	**1.73%**	**3.14%**	**0.16%**	**3.31%**	**1.58%**	**3.09%**	**0.14%**	**3.23%**	**1.50%**	**-0.08%**
Navajo Unit 1														
310.00	Rights-of-Way	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	3,190,563	0.69%	0.05%	0.74%	4.13%	0.20%	4.33%	3.59%	4.09%	0.20%	4.29%	3.55%	-0.04%
312.00	Boiler Plant Equipment	27,198,582	1.75%	0.12%	1.87%	6.00%	0.30%	6.30%	4.43%	5.97%	0.29%	6.26%	4.39%	-0.04%
314.00	Turbogenerator Units	6,860,989	1.58%	0.09%	1.67%	6.04%	0.28%	6.32%	4.65%	6.00%	0.27%	6.27%	4.60%	-0.05%
315.00	Accessory Electric Equipment	3,544,300	1.51%	0.09%	1.60%	8.48%	0.40%	8.88%	7.28%	8.45%	0.39%	8.84%	7.24%	-0.04%
316.00	Miscellaneous Power Plant Equipment	471,227	0.67%	0.05%	0.72%	4.01%	0.19%	4.20%	3.48%	3.97%	0.19%	4.16%	3.44%	-0.04%
Total Navajo Unit 1		**41,265,661**	**1.61%**	**0.11%**	**1.71%**	**6.05%**	**0.30%**	**6.35%**	**4.64%**	**6.02%**	**0.29%**	**6.31%**	**4.59%**	**-0.04%**
Navajo Unit 2														
310.00	Rights-of-Way	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	1,802,685	0.99%	0.07%	1.06%	1.42%	0.09%	1.51%	0.45%	1.35%	0.06%	1.41%	0.35%	-0.10%
312.00	Boiler Plant Equipment	26,882,286	1.52%	0.09%	1.61%	1.70%	0.10%	1.80%	0.19%	1.64%	0.06%	1.70%	0.09%	-0.10%
314.00	Turbogenerator Units	6,926,050	1.60%	0.12%	1.72%	1.82%	0.12%	1.94%	0.22%	1.75%	0.09%	1.84%	0.12%	-0.10%
315.00	Accessory Electric Equipment	3,172,330	1.62%	0.11%	1.73%	2.05%	0.13%	2.18%	0.45%	1.99%	0.10%	2.09%	0.36%	-0.09%
316.00	Miscellaneous Power Plant Equipment	515,874	0.88%	0.06%	0.94%	0.97%	0.06%	1.03%	0.09%	0.89%	0.04%	0.93%	-0.01%	-0.10%
Total Navajo Unit 2		**39,299,225**	**1.51%**	**0.10%**	**1.61%**	**1.73%**	**0.10%**	**1.83%**	**0.23%**	**1.66%**	**0.07%**	**1.73%**	**0.13%**	**-0.10%**
Navajo Unit 3														
310.00	Rights-of-Way	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	3,681,511	0.99%	0.07%	1.06%	1.12%	0.06%	1.18%	0.12%	1.05%	0.05%	1.10%	0.04%	-0.08%
312.00	Boiler Plant Equipment	27,718,514	1.58%	0.08%	1.66%	1.83%	0.08%	1.91%	0.25%	1.77%	0.06%	1.83%	0.17%	-0.08%
314.00	Turbogenerator Units	6,178,944	1.22%	0.07%	1.29%	1.42%	0.06%	1.48%	0.19%	1.35%	0.05%	1.40%	0.11%	-0.08%
315.00	Accessory Electric Equipment	5,139,872	1.33%	0.11%	1.44%	1.57%	0.11%	1.68%	0.24%	1.51%	0.08%	1.59%	0.15%	-0.09%
316.00	Miscellaneous Power Plant Equipment	549,362	0.73%	0.08%	0.81%	0.96%	0.09%	1.05%	0.24%	0.89%	0.06%	0.95%	0.14%	-0.10%
Total Navajo Unit 3		**43,268,203**	**1.44%**	**0.08%**	**1.52%**	**1.67%**	**0.08%**	**1.75%**	**0.23%**	**1.61%**	**0.06%**	**1.67%**	**0.15%**	**-0.08%**
Navajo Common														
310.00	Rights-of-Way	12,229	0.29%	0.02%	0.31%	0.77%	0.04%	0.81%	0.50%	0.69%	0.04%	0.73%	0.42%	-0.08%

Tucson Electric Power Company
Comparison of Two-Part Depreciation Rates

Account	Description	12/31/14 Investment	Current Approved Accrual Rate Net Plant	Net Salvage	Total	TEP Proposed Accrual Rate Net Plant	Net Salvage	Total	Difference from Current	Staff Proposed Accrual Rate Net Plant	Net Salvage	Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
311.00	Structures and Improvements	9,980,397	1.91%	0.14%	2.05%	2.81%	0.17%	2.98%	0.93%	2.76%	0.14%	2.90%	0.85%	-0.08%
312.00	Boiler Plant Equipment	6,744,819	2.19%	0.17%	2.36%	2.87%	0.20%	3.07%	0.71%	2.82%	0.16%	2.98%	0.62%	-0.09%
314.00	Turbogenerator Units	289,543	3.86%	0.28%	4.14%	4.89%	0.29%	5.18%	1.04%	4.86%	0.24%	5.10%	0.96%	-0.08%
315.00	Accessory Electric Equipment	2,973,356	3.49%	0.24%	3.73%	4.37%	0.25%	4.62%	0.89%	4.34%	0.19%	4.53%	0.80%	-0.09%
316.00	Miscellaneous Power Plant Equipment	2,982,134	2.00%	0.13%	2.13%	3.34%	0.19%	3.53%	1.40%	3.30%	0.15%	3.45%	1.32%	-0.08%
Total Navajo Common		**22,982,478**	**2.23%**	**0.16%**	**2.39%**	**3.12%**	**0.19%**	**3.32%**	**0.92%**	**3.08%**	**0.15%**	**3.23%**	**0.84%**	**-0.08%**
San Juan														
310.00	Rights-of-Way	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	14,437,744	1.72%	0.15%	1.87%	7.58%	0.72%	8.30%	6.43%	7.57%	0.59%	8.16%	6.29%	-0.14%
312.00	Boiler Plant Equipment	154,506,908	2.45%	0.74%	3.20%	7.64%	0.89%	8.53%	5.33%	7.63%	0.74%	8.37%	5.17%	-0.16%
314.00	Turbogenerator Units	44,295,673	2.06%	0.18%	2.24%	7.58%	0.73%	8.31%	6.07%	7.57%	0.60%	8.17%	5.93%	-0.14%
315.00	Accessory Electric Equipment	10,063,526	2.09%	0.19%	2.28%	7.63%	0.73%	8.36%	6.08%	7.62%	0.60%	8.22%	5.94%	-0.14%
316.00	Miscellaneous Power Plant Equipment	2,009,555	1.58%	0.12%	1.70%	7.61%	0.70%	8.31%	6.61%	7.60%	0.58%	8.18%	6.47%	-0.13%
Total San Juan		**225,313,406**	**2.30%**	**0.56%**	**2.87%**	**7.62%**	**0.84%**	**8.46%**	**5.60%**	**7.61%**	**0.69%**	**8.31%**	**5.44%**	**-0.16%**
San Juan Unit 1														
310.00	Rights-of-Way	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	14,268,404	1.72%	0.15%	1.87%	7.57%	0.73%	8.30%	6.43%	7.56%	0.60%	8.16%	6.29%	-0.14%
312.00	Boiler Plant Equipment	146,453,029	2.38%	0.25%	2.63%	7.63%	0.74%	8.37%	5.74%	7.62%	0.61%	8.23%	5.60%	-0.14%
314.00	Turbogenerator Units	44,295,673	2.06%	0.18%	2.24%	7.58%	0.73%	8.31%	6.07%	7.57%	0.60%	8.17%	5.93%	-0.14%
315.00	Accessory Electric Equipment	10,063,526	2.09%	0.19%	2.28%	7.63%	0.73%	8.36%	6.08%	7.62%	0.60%	8.22%	5.94%	-0.14%
316.00	Miscellaneous Power Plant Equipment	1,960,172	1.59%	0.12%	1.71%	7.60%	0.72%	8.32%	6.61%	7.59%	0.59%	8.18%	6.47%	-0.14%
Total San Juan Unit 1		**217,040,804**	**2.25%**	**0.23%**	**2.48%**	**7.62%**	**0.74%**	**8.35%**	**5.88%**	**7.61%**	**0.61%**	**8.21%**	**5.74%**	**-0.14%**
San Juan Common														
310.00	Rights-of-Way	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	169,340	1.66%	0.16%	1.82%	8.09%	0.02%	8.11%	6.29%	8.09%	0.02%	8.11%	6.29%	0.00%
312.00	Boiler Plant Equipment	8,053,879	3.76%	9.71%	13.47%	7.74%	3.76%	11.50%	-1.97%	7.73%	3.09%	10.82%	-2.65%	-0.68%
314.00	Turbogenerator Units	0	2.30%	0.20%	2.50%	0.00%	0.00%	0.00%	-2.50%	0.00%	0.00%	0.00%	-2.50%	0.00%
315.00	Accessory Electric Equipment	0	2.10%	0.20%	2.30%	0.00%	0.00%	0.00%	-2.30%	0.00%	0.00%	0.00%	-2.30%	0.00%
316.00	Miscellaneous Power Plant Equipment	49,383	1.36%	0.12%	1.48%	8.09%	0.00%	8.09%	6.61%	8.09%	0.00%	8.09%	6.61%	0.00%
Total San Juan Common		**8,272,602**	**3.70%**	**9.46%**	**13.16%**	**7.75%**	**3.66%**	**11.41%**	**-1.75%**	**7.74%**	**3.01%**	**10.75%**	**-2.41%**	**-0.66%**
Springerville														
310.00	Rights-of-Way	5,094,433	3.04%	0.00%	3.04%	2.85%	0.00%	2.85%	-0.19%	2.65%	0.00%	2.65%	-0.39%	-0.20%

Tucson Electric Power Company
Comparison of Two-Part Depreciation Rates

Account	Description	12/31/14 Investment	Current Approved Accrual Rate Net Plant	Net Salvage	Total	TEP Proposed Accrual Rate Net Plant	Net Salvage	Total	Difference from Current	Staff Proposed Accrual Rate Net Plant	Net Salvage	Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
311.00	Structures and Improvements	141,726,641	3.72%	0.05%	3.76%	2.84%	0.60%	3.44%	-0.32%	2.74%	0.46%	3.20%	-0.57%	-0.24%
312.00	Boiler Plant Equipment	641,687,365	3.16%	0.07%	3.23%	2.12%	0.39%	2.51%	-0.72%	2.05%	0.21%	2.26%	-0.97%	-0.25%
314.00	Turbogenerator Units	173,649,915	2.97%	0.08%	3.06%	2.18%	0.14%	2.32%	-0.74%	2.14%	0.09%	2.23%	-0.82%	-0.09%
315.00	Accessory Electric Equipment	75,864,618	3.30%	0.08%	3.38%	1.90%	0.19%	2.09%	-1.29%	1.84%	0.12%	1.96%	-1.42%	-0.13%
316.00	Miscellaneous Power Plant Equipment	12,528,984	3.99%	0.06%	4.05%	2.25%	0.24%	2.49%	-1.56%	2.19%	0.16%	2.35%	-1.70%	-0.14%
Total Springerville		**1,050,551,956**	**3.22%**	**0.07%**	**3.29%**	**2.22%**	**0.36%**	**2.58%**	**-0.72%**	**2.15%**	**0.21%**	**2.36%**	**-0.93%**	**-0.21%**
Springerville Unit 1														
310.00	Rights-of-Way	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	20,076,015	7.97%	0.01%	7.98%	2.06%	0.08%	2.14%	-5.84%	2.02%	0.05%	2.07%	-5.91%	-0.07%
312.00	Boiler Plant Equipment	185,682,490	6.15%	0.03%	6.18%	1.98%	0.08%	2.06%	-4.12%	1.94%	0.04%	1.98%	-4.20%	-0.08%
314.00	Turbogenerator Units	49,547,312	5.77%	-0.05%	5.72%	1.97%	0.08%	2.05%	-3.67%	1.93%	0.04%	1.97%	-3.75%	-0.08%
315.00	Accessory Electric Equipment	21,214,167	6.08%	0.01%	6.09%	1.73%	0.08%	1.81%	-4.28%	1.68%	0.05%	1.73%	-4.36%	-0.08%
316.00	Miscellaneous Power Plant Equipment	3,277,742	8.69%	0.00%	8.69%	2.14%	0.07%	2.21%	-6.48%	2.11%	0.04%	2.15%	-6.54%	-0.06%
Total Springerville Unit 1		**279,797,726**	**6.24%**	**0.01%**	**6.25%**	**1.97%**	**0.08%**	**2.05%**	**-4.20%**	**1.93%**	**0.04%**	**1.97%**	**-4.28%**	**-0.08%**
Springerville Unit 1 Common														
310.00	Rights-of-Way	1,143,496	0.00%	0.00%	0.00%	2.03%	0.00%	2.03%	2.03%	1.92%	0.00%	1.92%	1.92%	-0.11%
311.00	Structures and Improvements	52,492,826	3.00%	0.01%	3.01%	2.04%	0.24%	2.28%	-0.73%	1.93%	0.12%	2.05%	-0.96%	-0.23%
312.00	Boiler Plant Equipment	14,854,799	4.24%	0.00%	4.24%	2.00%	0.26%	2.26%	-1.98%	1.88%	0.14%	2.02%	-2.22%	-0.24%
314.00	Turbogenerator Units	1,264,322	1.83%	0.00%	1.83%	1.93%	0.26%	2.19%	0.36%	1.81%	0.14%	1.95%	0.12%	-0.24%
315.00	Accessory Electric Equipment	9,627,097	4.35%	0.00%	4.35%	1.81%	0.30%	2.11%	-2.24%	1.68%	0.16%	1.84%	-2.51%	-0.27%
316.00	Miscellaneous Power Plant Equipment	1,959,012	3.72%	0.00%	3.72%	1.83%	0.28%	2.11%	-1.61%	1.70%	0.15%	1.85%	-1.87%	-0.26%
Total Springerville Unit 1 Common		**81,341,552**	**3.34%**	**0.01%**	**3.35%**	**2.00%**	**0.25%**	**2.25%**	**-1.10%**	**1.88%**	**0.13%**	**2.01%**	**-1.34%**	**-0.24%**
Springerville Unit 2														
310.00	Rights-of-Way	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	36,540,030	1.86%	0.15%	2.01%	2.16%	0.15%	2.31%	0.30%	2.12%	0.09%	2.21%	0.20%	-0.10%
312.00	Boiler Plant Equipment	295,922,545	1.88%	0.14%	2.02%	2.12%	0.15%	2.27%	0.25%	2.08%	0.10%	2.18%	0.16%	-0.09%
314.00	Turbogenerator Units	122,055,348	1.84%	0.14%	1.98%	2.25%	0.15%	2.40%	0.42%	2.22%	0.10%	2.32%	0.34%	-0.08%
315.00	Accessory Electric Equipment	42,346,939	1.69%	0.13%	1.82%	1.88%	0.12%	2.00%	0.18%	1.83%	0.07%	1.90%	0.08%	-0.10%
316.00	Miscellaneous Power Plant Equipment	6,624,669	1.71%	0.11%	1.82%	2.14%	0.13%	2.27%	0.45%	2.10%	0.07%	2.17%	0.35%	-0.10%
Total Springerville Unit 2		**503,489,531**	**1.85%**	**0.14%**	**1.99%**	**2.13%**	**0.15%**	**2.28%**	**0.29%**	**2.10%**	**0.10%**	**2.19%**	**0.20%**	**-0.09%**
Springerville Unit 2 Common (Leasehold Imp.)														
310.00	Rights-of-Way	2,280,838	2.80%	0.00%	2.80%	3.86%	0.00%	3.86%	1.06%	3.60%	0.00%	3.60%	0.80%	-0.26%

Tucson Electric Power Company
Comparison of Two-Part Depreciation Rates

Account	Description	12/31/14 Investment	Current Approved Accrual Rate Net Plant	Net Salvage	Total	TEP Proposed Accrual Rate Net Plant	Net Salvage	Total	Difference from Current	Staff Proposed Accrual Rate Net Plant	Net Salvage	Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
311.00	Structures and Improvements	32,617,770	4.34%	0.01%	4.35%	5.38%	2.00%	7.38%	3.03%	5.18%	1.67%	6.85%	2.50%	-0.53%
312.00	Boiler Plant Equipment	6,282,729	5.50%	0.00%	5.50%	6.45%	2.16%	8.61%	3.11%	6.29%	1.81%	8.10%	2.60%	-0.51%
314.00	Turbogenerator Units	782,933	4.06%	0.00%	4.06%	4.69%	1.85%	6.54%	2.48%	4.47%	1.53%	6.00%	1.94%	-0.54%
315.00	Accessory Electric Equipment	2,676,415	3.06%	0.00%	3.06%	4.01%	1.58%	5.59%	2.53%	3.75%	1.29%	5.04%	1.98%	-0.55%
316.00	Miscellaneous Power Plant Equipment	667,561	4.37%	0.00%	4.37%	5.19%	2.01%	7.20%	2.83%	4.98%	1.68%	6.66%	2.29%	-0.54%
Total Springerville Unit 2 Common		**45,308,246**	**4.34%**	**0.01%**	**4.35%**	**5.36%**	**1.89%**	**7.25%**	**2.90%**	**5.15%**	**1.58%**	**6.74%**	**2.38%**	**-0.52%**
Springerville Coal Handling														
310.00	Rights-of-Way	1,670,099	5.44%	0.00%	5.44%	2.04%	0.00%	2.04%	-3.40%	1.84%	0.00%	1.84%	-3.60%	-0.20%
311.00	Structures and Improvements	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
312.00	Boiler Plant Equipment	138,944,802	1.65%	0.00%	1.65%	2.14%	1.24%	3.38%	1.73%	1.96%	0.59%	2.55%	0.90%	-0.83%
314.00	Turbogenerator Units	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
315.00	Accessory Electric Equipment	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
316.00	Miscellaneous Power Plant Equipment	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total Springerville Coal Handling		**140,614,901**	**1.70%**	**0.00%**	**1.70%**	**2.14%**	**1.23%**	**3.36%**	**1.67%**	**1.96%**	**0.58%**	**2.54%**	**0.85%**	**-0.82%**
Sundt														
310.00	Rights-of-Way	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	27,475,371	3.91%	2.04%	5.95%	3.03%	1.45%	4.48%	-1.47%	2.67%	0.87%	3.53%	-2.42%	-0.95%
312.00	Boiler Plant Equipment	130,812,626	3.73%	1.76%	5.49%	2.81%	1.19%	4.00%	-1.49%	2.50%	0.71%	3.21%	-2.29%	-0.79%
314.00	Turbogenerator Units	52,481,329	6.15%	3.63%	9.79%	3.66%	2.01%	5.67%	-4.12%	3.22%	1.26%	4.48%	-5.31%	-1.19%
315.00	Accessory Electric Equipment	39,432,489	5.67%	3.17%	8.85%	3.73%	1.94%	5.67%	-3.18%	3.29%	1.22%	4.51%	-4.34%	-1.16%
316.00	Miscellaneous Power Plant Equipment	2,333,493	6.31%	3.45%	9.76%	4.00%	2.10%	6.10%	-3.66%	3.53%	1.34%	4.87%	-4.89%	-1.23%
Total Sundt		**252,535,308**	**4.58%**	**2.42%**	**7.00%**	**3.17%**	**1.52%**	**4.68%**	**-2.32%**	**2.80%**	**0.92%**	**3.73%**	**-3.27%**	**-0.96%**
Sundt Unit 1														
310.00	Rights-of-Way	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	3,926,062	9.95%	5.37%	15.32%	4.99%	2.77%	7.76%	-7.56%	3.78%	1.65%	5.43%	-9.89%	-2.33%
312.00	Boiler Plant Equipment	13,782,181	10.40%	5.02%	15.42%	4.54%	2.37%	6.91%	-8.51%	3.46%	1.41%	4.87%	-10.55%	-2.04%
314.00	Turbogenerator Units	10,237,507	11.68%	6.16%	17.84%	4.98%	2.71%	7.69%	-10.15%	3.82%	1.62%	5.44%	-12.40%	-2.25%
315.00	Accessory Electric Equipment	6,536,315	13.14%	7.13%	20.27%	6.15%	3.39%	9.54%	-10.73%	4.80%	2.12%	6.92%	-13.35%	-2.62%
316.00	Miscellaneous Power Plant Equipment	490,578	12.19%	6.50%	18.69%	5.82%	3.28%	9.10%	-9.59%	4.52%	2.04%	6.56%	-12.13%	-2.54%
Total Sundt Unit 1		**34,972,643**	**11.26%**	**5.81%**	**17.07%**	**5.04%**	**2.72%**	**7.76%**	**-9.31%**	**3.87%**	**1.64%**	**5.51%**	**-11.56%**	**-2.25%**
Sundt Unit 2														
310.00	Rights-of-Way	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Tucson Electric Power Company
Comparison of Two-Part Depreciation Rates

Account	Description	12/31/14 Investment	Current Approved Accrual Rate Net Plant	Net Salvage	Total	TEP Proposed Accrual Rate Net Plant	Net Salvage	Total	Difference from Current	Staff Proposed Accrual Rate Net Plant	Net Salvage	Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
311.00	Structures and Improvements	2,812,689	8.40%	5.33%	13.73%	5.00%	3.05%	8.05%	-5.68%	4.31%	1.99%	6.30%	-7.43%	-1.75%
312.00	Boiler Plant Equipment	14,371,609	8.25%	5.37%	13.62%	4.08%	2.62%	6.70%	-6.92%	3.41%	1.68%	5.09%	-8.53%	-1.61%
314.00	Turbogenerator Units	8,451,923	8.22%	5.19%	13.41%	3.91%	2.44%	6.35%	-7.06%	3.23%	1.54%	4.77%	-8.64%	-1.58%
315.00	Accessory Electric Equipment	6,205,700	10.07%	6.35%	16.42%	5.61%	3.58%	9.19%	-7.23%	4.93%	2.42%	7.35%	-9.07%	-1.84%
316.00	Miscellaneous Power Plant Equipment	383,824	9.57%	5.95%	15.52%	5.36%	3.37%	8.73%	-6.79%	4.68%	2.27%	6.95%	-8.57%	-1.78%
Total Sundt Unit 2		**32,225,745**	**8.62%**	**5.51%**	**14.14%**	**4.43%**	**2.80%**	**7.23%**	**-6.91%**	**3.75%**	**1.82%**	**5.57%**	**-8.57%**	**-1.66%**
Sundt Unit 3														
310.00	Rights-of-Way	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	2,762,012	6.64%	4.90%	11.54%	4.13%	2.90%	7.03%	-4.51%	3.87%	1.98%	5.85%	-5.69%	-1.18%
312.00	Boiler Plant Equipment	11,980,831	6.17%	4.67%	10.84%	3.88%	2.80%	6.68%	-4.16%	3.58%	1.90%	5.48%	-5.36%	-1.20%
314.00	Turbogenerator Units	14,830,615	6.82%	5.09%	11.91%	4.05%	2.86%	6.91%	-5.00%	3.78%	1.95%	5.73%	-6.18%	-1.18%
315.00	Accessory Electric Equipment	6,140,139	7.15%	5.16%	12.31%	3.98%	2.76%	6.74%	-5.57%	3.69%	1.87%	5.56%	-6.75%	-1.18%
316.00	Miscellaneous Power Plant Equipment	404,717	7.90%	5.55%	13.45%	4.62%	3.17%	7.79%	-5.66%	4.43%	2.22%	6.65%	-6.80%	-1.14%
Total Sundt Unit 3		**36,118,314**	**6.66%**	**4.95%**	**11.61%**	**3.99%**	**2.83%**	**6.82%**	**-4.79%**	**3.71%**	**1.93%**	**5.64%**	**-5.97%**	**-1.19%**
Sundt Unit 4														
310.00	Rights-of-Way	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	17,974,608	1.47%	0.36%	1.83%	2.13%	0.69%	2.82%	0.99%	1.98%	0.35%	2.33%	0.50%	-0.49%
312.00	Boiler Plant Equipment	80,576,055	1.47%	0.35%	1.82%	2.09%	0.65%	2.74%	0.92%	1.94%	0.32%	2.26%	0.44%	-0.48%
314.00	Turbogenerator Units	18,961,284	1.73%	0.43%	2.16%	2.54%	0.76%	3.30%	1.14%	2.45%	0.40%	2.85%	0.69%	-0.45%
315.00	Accessory Electric Equipment	20,550,335	1.53%	0.36%	1.89%	2.32%	0.73%	3.05%	1.16%	2.20%	0.37%	2.57%	0.68%	-0.48%
316.00	Miscellaneous Power Plant Equipment	1,054,374	1.78%	0.31%	2.09%	2.41%	0.68%	3.09%	1.00%	2.30%	0.34%	2.64%	0.55%	-0.45%
Total Sundt Unit 4		**139,116,656**	**1.52%**	**0.36%**	**1.88%**	**2.19%**	**0.68%**	**2.88%**	**1.00%**	**2.06%**	**0.34%**	**2.40%**	**0.52%**	**-0.48%**
Sundt Solar Booster (Areva)														
310.00	Rights-of-Way	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
312.00	Boiler Plant Equipment	10,101,950	3.34%	0.00%	3.34%	3.11%	0.01%	3.12%	-0.22%	3.11%	0.01%	3.12%	-0.22%	0.00%
314.00	Turbogenerator Units	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
315.00	Accessory Electric Equipment	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
316.00	Miscellaneous Power Plant Equipment	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total Sundt Solar Booster (Areva)		**10,101,950**	**3.34%**	**0.00%**	**3.34%**	**3.11%**	**0.01%**	**3.12%**	**-0.22%**	**3.11%**	**0.01%**	**3.12%**	**-0.22%**	**0.00%**
OTHER PRODUCTION (by Unit)														

Tucson Electric Power Company
Comparison of Two-Part Depreciation Rates

Account	Description	12/31/14 Investment	Current Approved Accrual Rate Net Plant	Net Salvage	Total	TEP Proposed Accrual Rate Net Plant	Net Salvage	Total	Difference from Current	Staff Proposed Accrual Rate Net Plant	Net Salvage	Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
DeMoss Petrie Gas Unit 1														
341.00	Structures and Improvements	761,988	2.46%	0.19%	2.65%	2.64%	0.18%	2.82%	0.17%	2.61%	0.10%	2.71%	0.06%	-0.11%
342.00	Fuel Holders, Products and Accessories	750,386	2.30%	0.21%	2.51%	2.23%	0.20%	2.43%	-0.08%	2.18%	0.11%	2.29%	-0.22%	-0.14%
343.00	Prime Movers	76,766	2.90%	0.27%	3.17%	2.86%	0.01%	2.87%	-0.30%	2.84%	0.00%	2.84%	-0.33%	-0.03%
344.00	Generators and Devices	30,772,866	2.30%	0.21%	2.51%	2.24%	0.19%	2.43%	-0.08%	2.19%	0.11%	2.30%	-0.21%	-0.13%
345.00	Accessory Electric Equipment	861,492	2.30%	0.21%	2.51%	2.29%	0.05%	2.34%	-0.17%	2.24%	0.03%	2.27%	-0.24%	-0.07%
346.00	Miscellaneous Power Plant Equipment	376,605	2.38%	0.22%	2.60%	2.36%	0.21%	2.57%	-0.03%	2.32%	0.11%	2.43%	-0.17%	-0.14%
Total DeMoss Petrie Gas Unit 1		**33,600,103**	**2.31%**	**0.21%**	**2.52%**	**2.25%**	**0.19%**	**2.44%**	**-0.08%**	**2.20%**	**0.11%**	**2.31%**	**-0.20%**	**-0.13%**
Gila River														
341.00	Structures and Improvements	8,508,950	2.26%	0.00%	2.26%	2.42%	0.20%	2.62%	0.36%	2.39%	0.11%	2.50%	0.24%	-0.12%
342.00	Fuel Holders, Products and Accessories	6,783,045	2.26%	0.00%	2.26%	2.40%	0.20%	2.60%	0.34%	2.37%	0.11%	2.48%	0.22%	-0.12%
343.00	Prime Movers	188,744,730	2.26%	0.00%	2.26%	2.44%	0.20%	2.64%	0.38%	2.41%	0.11%	2.52%	0.26%	-0.12%
344.00	Generators and Devices	32,783,434	2.26%	0.00%	2.26%	2.37%	0.20%	2.57%	0.31%	2.34%	0.11%	2.45%	0.19%	-0.12%
345.00	Accessory Electric Equipment	9,030,698	2.26%	0.00%	2.26%	2.39%	0.20%	2.59%	0.33%	2.36%	0.10%	2.47%	0.21%	-0.12%
346.00	Miscellaneous Power Plant Equipment	6,799,960	2.26%	0.00%	2.26%	2.41%	0.20%	2.61%	0.35%	2.38%	0.11%	2.49%	0.23%	-0.12%
Total Gila River		**252,650,817**	**2.26%**	**0.00%**	**2.26%**	**2.42%**	**0.20%**	**2.62%**	**0.36%**	**2.39%**	**0.11%**	**2.50%**	**0.24%**	**-0.12%**
Gila River Unit 3														
341.00	Structures and Improvements	957,417	2.26%	0.00%	2.26%	2.38%	0.20%	2.58%	0.32%	2.36%	0.10%	2.46%	0.20%	-0.12%
342.00	Fuel Holders, Products and Accessories	178,424	2.26%	0.00%	2.26%	2.45%	0.20%	2.65%	0.39%	2.42%	0.11%	2.53%	0.27%	-0.12%
343.00	Prime Movers	181,571,712	2.26%	0.00%	2.26%	2.43%	0.20%	2.63%	0.37%	2.40%	0.11%	2.51%	0.25%	-0.12%
344.00	Generators and Devices	32,783,434	2.26%	0.00%	2.26%	2.37%	0.20%	2.57%	0.31%	2.34%	0.11%	2.45%	0.19%	-0.12%
345.00	Accessory Electric Equipment	6,860,554	2.26%	0.00%	2.26%	2.38%	0.20%	2.58%	0.32%	2.36%	0.10%	2.46%	0.20%	-0.12%
346.00	Miscellaneous Power Plant Equipment	135,558	2.26%	0.00%	2.26%	2.41%	0.20%	2.61%	0.35%	2.38%	0.11%	2.49%	0.23%	-0.12%
Total Gila River Unit 3		**222,487,099**	**2.26%**	**0.00%**	**2.26%**	**2.42%**	**0.20%**	**2.62%**	**0.36%**	**2.39%**	**0.11%**	**2.50%**	**0.24%**	**-0.12%**
Gila River Common														
341.00	Structures and Improvements	7,551,533	2.26%	0.00%	2.26%	2.42%	0.20%	2.62%	0.36%	2.39%	0.11%	2.50%	0.24%	-0.12%
342.00	Fuel Holders, Products and Accessories	6,604,621	2.26%	0.00%	2.26%	2.40%	0.20%	2.60%	0.34%	2.37%	0.11%	2.48%	0.22%	-0.12%
343.00	Prime Movers	7,173,018	2.26%	0.00%	2.26%	2.59%	0.22%	2.81%	0.55%	2.58%	0.11%	2.69%	0.43%	-0.12%
344.00	Generators and Devices	0	2.26%	0.00%	2.26%	0.00%	0.00%	0.00%	-2.26%	0.00%	0.00%	0.00%	-2.26%	0.00%
345.00	Accessory Electric Equipment	2,170,144	2.26%	0.00%	2.26%	2.41%	0.20%	2.61%	0.35%	2.38%	0.11%	2.49%	0.23%	-0.12%
346.00	Miscellaneous Power Plant Equipment	6,664,402	2.26%	0.00%	2.26%	2.41%	0.20%	2.61%	0.35%	2.38%	0.11%	2.49%	0.23%	-0.12%
Total Gila River Common		**30,163,718**	**2.26%**	**0.00%**	**2.26%**	**2.45%**	**0.20%**	**2.66%**	**0.40%**	**2.43%**	**0.11%**	**2.54%**	**0.28%**	**-0.12%**

Tucson Electric Power Company
Comparison of Two-Part Depreciation Rates

Account	Description	12/31/14 Investment	Current Approved Accrual Rate			TEP Proposed Accrual Rate			Difference from Current	Staff Proposed Accrual Rate			Difference from Current	Difference from Company
			Plant	Net Salvage	Total	Plant	Net Salvage	Total		Plant	Net Salvage	Total		
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
Luna														
341.00	Structures and Improvements	13,232,832	2.63%	0.51%	3.14%	2.78%	0.52%	3.30%	0.16%	2.77%	0.26%	3.03%	-0.11%	-0.27%
342.00	Fuel Holders, Products and Accessories	11,352,383	2.62%	0.52%	3.14%	2.78%	0.52%	3.30%	0.16%	2.77%	0.26%	3.03%	-0.11%	-0.27%
343.00	Prime Movers	11,151,074	2.65%	0.51%	3.16%	2.84%	0.51%	3.35%	0.19%	2.83%	0.26%	3.09%	-0.07%	-0.26%
344.00	Generators and Devices	9,486,694	2.63%	0.50%	3.13%	2.80%	0.49%	3.29%	0.16%	2.79%	0.25%	3.04%	-0.09%	-0.25%
345.00	Accessory Electric Equipment	9,647	2.57%	0.00%	2.57%	2.86%	0.54%	3.40%	0.83%	2.86%	0.28%	3.14%	0.57%	-0.26%
346.00	Miscellaneous Power Plant Equipment	7,424,592	2.62%	0.52%	3.14%	2.78%	0.52%	3.30%	0.16%	2.77%	0.26%	3.03%	-0.11%	-0.27%
Total Luna		**52,657,222**	**2.63%**	**0.51%**	**3.14%**	**2.80%**	**0.51%**	**3.31%**	**0.17%**	**2.79%**	**0.26%**	**3.04%**	**-0.10%**	**-0.26%**
North Loop Gas														
341.00	Structures and Improvements	888,601	3.17%	0.35%	3.52%	1.18%	0.13%	1.31%	-2.21%	0.81%	0.06%	0.87%	-2.65%	-0.44%
342.00	Fuel Holders, Products and Accessories	303,037	2.22%	0.13%	2.35%	2.23%	0.13%	2.36%	0.01%	2.21%	0.07%	2.28%	-0.07%	-0.08%
343.00	Prime Movers	1,890,946	10.88%	1.39%	12.27%	5.74%	0.66%	6.40%	-5.87%	4.29%	0.39%	4.68%	-7.59%	-1.72%
344.00	Generators and Devices	24,062,187	2.21%	0.18%	2.39%	1.49%	0.08%	1.57%	-0.82%	1.35%	0.03%	1.38%	-1.01%	-0.19%
345.00	Accessory Electric Equipment	2,829,171	2.96%	0.30%	3.26%	1.84%	0.17%	2.01%	-1.25%	1.51%	0.09%	1.60%	-1.65%	-0.41%
346.00	Miscellaneous Power Plant Equipment	656,253	2.69%	0.29%	2.98%	0.85%	0.07%	0.92%	-2.06%	0.56%	0.03%	0.58%	-2.39%	-0.34%
Total North Loop Gas		**30,630,195**	**2.85%**	**0.27%**	**3.12%**	**1.77%**	**0.13%**	**1.90%**	**-1.22%**	**1.52%**	**0.06%**	**1.58%**	**-1.54%**	**-0.32%**
North Loop Gas Unit 1														
341.00	Structures and Improvements	411,070	4.39%	0.49%	4.88%	1.44%	0.20%	1.64%	-3.24%	0.99%	0.11%	1.10%	-3.78%	-0.54%
342.00	Fuel Holders, Products and Accessories	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
343.00	Prime Movers	678,545	9.60%	1.06%	10.66%	3.78%	0.50%	4.28%	-6.38%	2.93%	0.32%	3.25%	-7.41%	-1.03%
344.00	Generators and Devices	3,582,271	2.65%	0.29%	2.94%	0.22%	0.01%	0.23%	-2.71%	-0.05%	-0.01%	-0.06%	-3.00%	-0.29%
345.00	Accessory Electric Equipment	790,955	4.10%	0.45%	4.55%	1.51%	0.19%	1.70%	-2.85%	1.05%	0.10%	1.15%	-3.40%	-0.55%
346.00	Miscellaneous Power Plant Equipment	306,369	4.26%	0.48%	4.74%	1.19%	0.16%	1.35%	-3.39%	0.80%	0.08%	0.88%	-3.86%	-0.47%
Total North Loop Gas Unit 1		**5,769,210**	**3.88%**	**0.43%**	**4.30%**	**0.95%**	**0.11%**	**1.07%**	**-3.23%**	**0.57%**	**0.06%**	**0.63%**	**-3.67%**	**-0.44%**
North Loop Gas Unit 2														
341.00	Structures and Improvements	196,078	1.98%	0.31%	2.29%	0.83%	0.15%	0.98%	-1.31%	0.45%	0.07%	0.52%	-1.77%	-0.46%
342.00	Fuel Holders, Products and Accessories	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
343.00	Prime Movers	263,450	5.30%	0.82%	6.12%	13.27%	0.69%	13.96%	7.84%	9.35%	0.29%	9.64%	3.52%	-4.32%
344.00	Generators and Devices	3,239,719	1.85%	0.26%	2.11%	0.70%	0.10%	0.80%	-1.31%	0.36%	0.03%	0.39%	-1.72%	-0.41%
345.00	Accessory Electric Equipment	504,895	2.68%	0.39%	3.07%	1.75%	0.28%	2.03%	-1.04%	1.20%	0.16%	1.36%	-1.71%	-0.67%
346.00	Miscellaneous Power Plant Equipment	128,559	0.89%	0.13%	1.02%	0.13%	0.02%	0.15%	-0.87%	-0.15%	-0.02%	-0.17%	-1.19%	-0.32%
Total North Loop Gas Unit 2		**4,332,701**	**2.13%**	**0.31%**	**2.44%**	**1.58%**	**0.16%**	**1.73%**	**-0.71%**	**0.99%**	**0.06%**	**1.05%**	**-1.39%**	**-0.68%**

Tucson Electric Power Company
Comparison of Two-Part Depreciation Rates

Account	Description	12/31/14 Investment	Current Approved Accrual Rate Plant	Current Approved Accrual Rate Net Salvage	Current Approved Accrual Rate Total	TEP Proposed Accrual Rate Plant	TEP Proposed Accrual Rate Net Salvage	TEP Proposed Accrual Rate Total	Difference from Current	Staff Proposed Accrual Rate Plant	Staff Proposed Accrual Rate Net Salvage	Staff Proposed Accrual Rate Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
North Loop Gas Unit 3														
341.00	Structures and Improvements	196,078	2.17%	0.29%	2.46%	0.48%	0.08%	0.56%	-1.90%	0.14%	0.02%	0.16%	-2.30%	-0.40%
342.00	Fuel Holders, Products and Accessories	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
343.00	Prime Movers	948,951	13.34%	1.78%	15.12%	5.06%	0.76%	5.82%	-9.30%	3.85%	0.47%	4.32%	-10.80%	-1.50%
344.00	Generators and Devices	3,030,531	1.99%	0.22%	2.21%	0.30%	0.00%	0.30%	-1.91%	0.00%	-0.04%	-0.04%	-2.25%	-0.34%
345.00	Accessory Electric Equipment	503,907	2.85%	0.37%	3.22%	1.44%	0.21%	1.65%	-1.57%	0.93%	0.11%	1.04%	-2.18%	-0.61%
346.00	Miscellaneous Power Plant Equipment	128,559	1.09%	0.15%	1.24%	-0.26%	-0.04%	-0.30%	-1.54%	-0.50%	-0.06%	-0.56%	-1.80%	-0.26%
Total North Loop Gas Unit 3		**4,808,026**	**4.30%**	**0.54%**	**4.85%**	**1.35%**	**0.17%**	**1.53%**	**-3.32%**	**0.85%**	**0.08%**	**0.93%**	**-3.92%**	**-0.60%**
North Loop Gas Unit 4														
341.00	Structures and Improvements	85,375	2.29%	-0.10%	2.19%	2.33%	-0.09%	2.24%	0.05%	2.30%	-0.15%	2.15%	-0.04%	-0.09%
342.00	Fuel Holders, Products and Accessories	303,037	2.22%	0.13%	2.35%	2.23%	0.13%	2.36%	0.01%	2.21%	0.07%	2.28%	-0.07%	-0.08%
343.00	Prime Movers	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
344.00	Generators and Devices	14,209,666	2.22%	0.13%	2.35%	2.24%	0.12%	2.36%	0.01%	2.21%	0.06%	2.27%	-0.08%	-0.09%
345.00	Accessory Electric Equipment	1,029,414	2.27%	0.11%	2.38%	2.32%	0.10%	2.42%	0.04%	2.30%	0.05%	2.35%	-0.03%	-0.07%
346.00	Miscellaneous Power Plant Equipment	92,766	2.22%	0.06%	2.28%	2.23%	0.06%	2.29%	0.01%	2.21%	0.03%	2.24%	-0.04%	-0.05%
Total North Loop Gas Unit 4		**15,720,258**	**2.22%**	**0.13%**	**2.35%**	**2.25%**	**0.12%**	**2.36%**	**0.01%**	**2.22%**	**0.06%**	**2.27%**	**-0.08%**	**-0.09%**
Solar Units (Generators and Devices)														
344.00	DeMoss Petrie	1,146,081	5.13%	0.00%	5.13%	3.05%	0.15%	3.20%	-1.93%	3.05%	0.15%	3.20%	-1.93%	0.00%
344.00	Fort Huachuca	36,709,538	5.13%	0.00%	5.13%	3.56%	0.18%	3.74%	-1.39%	3.56%	0.18%	3.74%	-1.39%	0.00%
344.00	HQ Rooftop	303,184	5.13%	0.00%	5.13%	3.50%	0.18%	3.68%	-1.45%	3.50%	0.18%	3.68%	-1.45%	0.00%
344.00	OH Rooftop	2,594,590	5.13%	0.00%	5.13%	3.47%	0.17%	3.64%	-1.49%	3.47%	0.17%	3.64%	-1.49%	0.00%
344.00	OH Test Yard	388,459	5.13%	0.00%	5.13%	3.10%	0.15%	3.25%	-1.88%	3.10%	0.15%	3.25%	-1.88%	0.00%
344.00	Prairie Fire	19,036,520	5.13%	0.00%	5.13%	3.50%	0.18%	3.68%	-1.45%	3.50%	0.18%	3.68%	-1.45%	0.00%
344.00	Springerville Sites 1-3 (Legacy)	28,766,605	5.13%	0.00%	5.13%	3.05%	0.15%	3.20%	-1.93%	3.05%	0.15%	3.20%	-1.93%	0.00%
344.00	Springerville Site 4	7,873,874	5.13%	0.00%	5.13%	3.43%	0.18%	3.61%	-1.52%	3.43%	0.18%	3.61%	-1.52%	0.00%
343.00	Tucson	87,198	5.13%	0.00%	5.13%	2.60%	0.13%	2.73%	-2.40%	2.60%	0.13%	2.73%	-2.40%	0.00%
344.00	U of A Tech Park Site 1	7,723,832	5.13%	0.00%	5.13%	3.43%	0.18%	3.61%	-1.52%	3.43%	0.18%	3.61%	-1.52%	0.00%
345.00	U of A Tech Park Site 2	19,191,952	5.13%	0.00%	5.13%	3.47%	0.17%	3.64%	-1.49%	3.47%	0.17%	3.64%	-1.49%	0.00%
346.00	White Mountain	46,499,099	5.13%	0.00%	5.13%	3.56%	0.18%	3.74%	-1.39%	3.56%	0.18%	3.74%	-1.39%	0.00%
Total Solar Units		**170,320,932**	**5.13%**	**0.00%**	**5.13%**	**3.44%**	**0.17%**	**3.61%**	**-1.52%**	**3.44%**	**0.17%**	**3.61%**	**-1.52%**	**0.00%**
Sundt Gas														
341.00	Structures and Improvements	11,090	0.26%	0.01%	0.27%	-0.13%	-0.01%	-0.14%	-0.41%	-0.07%	-0.01%	-0.08%	-0.35%	0.07%
342.00	Fuel Holders, Products and Accessories	788,336	8.51%	0.15%	8.66%	3.63%	0.08%	3.71%	-4.95%	2.92%	0.06%	2.98%	-5.68%	-0.74%

Tucson Electric Power Company
Comparison of Two-Part Depreciation Rates

Account	Description	12/31/14 Investment	Current Approved Accrual Rate Plant	Current Approved Accrual Rate Net Salvage	Current Approved Accrual Rate Total	TEP Proposed Accrual Rate Plant	TEP Proposed Accrual Rate Net Salvage	TEP Proposed Accrual Rate Total	Difference from Current	Staff Proposed Accrual Rate Plant	Staff Proposed Accrual Rate Net Salvage	Staff Proposed Accrual Rate Total	Difference from Current	Difference from Company
		A	B	C	D=B+C	E	F	G=E+F	H=G-D	I	J	K=I+J	L=K-D	M=K-G
343.00	Prime Movers	141,618	3.64%	0.06%	3.70%	1.79%	0.04%	1.83%	-1.87%	1.57%	0.04%	1.61%	-2.09%	-0.23%
344.00	Generators and Devices	8,382,044	0.16%	0.00%	0.16%	-0.37%	-0.02%	-0.39%	-0.55%	-0.31%	-0.01%	-0.32%	-0.48%	0.07%
345.00	Accessory Electric Equipment	1,078,811	1.37%	0.03%	1.39%	0.17%	0.00%	0.17%	-1.22%	0.12%	0.00%	0.12%	-1.27%	-0.05%
346.00	Miscellaneous Power Plant Equipment	49,750	0.00%	0.00%	0.00%	-1.25%	-0.02%	-1.27%	-1.27%	-1.06%	-0.03%	-1.09%	-1.09%	0.18%
Total Sundt Gas		**10,451,649**	**0.96%**	**0.01%**	**0.97%**	**0.02%**	**-0.01%**	**0.01%**	**-0.96%**	**0.00%**	**0.00%**	**0.00%**	**-0.98%**	**-0.01%**
Sundt Gas Unit 1														
341.00	Structures and Improvements	5,545	0.10%	0.00%	0.10%	-0.08%	-0.01%	-0.09%	-0.19%	-0.03%	0.00%	-0.03%	-0.13%	0.06%
342.00	Fuel Holders, Products and Accessories	394,168	8.42%	0.14%	8.56%	3.66%	0.08%	3.74%	-4.82%	2.94%	0.05%	2.99%	-5.57%	-0.75%
343.00	Prime Movers	70,809	3.51%	0.06%	3.57%	1.83%	0.04%	1.87%	-1.70%	1.60%	0.03%	1.63%	-1.94%	-0.24%
344.00	Generators and Devices	4,315,668	0.00%	0.00%	0.00%	-0.39%	-0.02%	-0.41%	-0.41%	-0.34%	-0.01%	-0.35%	-0.35%	0.06%
345.00	Accessory Electric Equipment	516,231	1.06%	0.02%	1.08%	0.13%	-0.01%	0.12%	-0.96%	0.08%	0.00%	0.08%	-1.00%	-0.04%
346.00	Miscellaneous Power Plant Equipment	19,906	0.00%	0.00%	0.00%	-1.21%	-0.02%	-1.23%	-1.23%	-1.04%	-0.02%	-1.06%	-1.06%	0.17%
Total Sundt Gas Unit 1		**5,322,327**	**0.77%**	**0.01%**	**0.79%**	**-0.01%**	**-0.01%**	**-0.02%**	**-0.81%**	**-0.03%**	**0.00%**	**-0.04%**	**-0.82%**	**-0.01%**
Sundt Gas Unit 2														
341.00	Structures and Improvements	5,545	0.41%	0.01%	0.42%	-0.18%	-0.01%	-0.19%	-0.61%	-0.10%	-0.02%	-0.12%	-0.54%	0.07%
342.00	Fuel Holders, Products and Accessories	394,168	8.59%	0.16%	8.75%	3.61%	0.08%	3.69%	-5.06%	2.90%	0.06%	2.96%	-5.79%	-0.73%
343.00	Prime Movers	70,809	3.77%	0.06%	3.83%	1.76%	0.03%	1.79%	-2.04%	1.54%	0.04%	1.58%	-2.25%	-0.21%
344.00	Generators and Devices	4,066,376	0.32%	0.00%	0.32%	-0.34%	-0.02%	-0.36%	-0.68%	-0.28%	-0.01%	-0.29%	-0.61%	0.07%
345.00	Accessory Electric Equipment	562,580	1.65%	0.03%	1.68%	0.21%	0.00%	0.21%	-1.47%	0.16%	0.00%	0.16%	-1.52%	-0.05%
346.00	Miscellaneous Power Plant Equipment	29,844	0.00%	0.00%	0.00%	-1.28%	-0.02%	-1.30%	-1.30%	-1.08%	-0.03%	-1.11%	-1.11%	0.19%
Total Sundt Gas Unit 2		**5,129,322**	**1.15%**	**0.02%**	**1.16%**	**0.05%**	**-0.01%**	**0.04%**	**-1.13%**	**0.03%**	**0.00%**	**0.03%**	**-1.13%**	**-0.01%**

Tucson Electric Power Company
Calculation of Depreciation Reserve Allocation

Account	Description	12/31/14 Investment	Future Net Salvage Percent	Total to be Recovered	Book Reserve Amount	Book Reserve Percent	Theoretical Reserve Amount	Theoretical Reserve Percent	Redistributed Reserve Amount	Redistributed Reserve Percent	Investment Reserve Amount	Investment Reserve Percent	Salvage Reserve Amount	Salvage Reserve Percent
STEAM PRODUCTION														
310.00	Rights-of-Way	5,106,662	0.0%	5,107,396	3,694,243	72.34%	2,875,689	56.31%	2,656,223	52.01%	2,655,709	52.00%	514	0.01%
311.00	Structures and Improvements	205,277,689	-19.5%	245,308,028	105,373,653	51.33%	102,933,808	50.14%	97,263,285	47.38%	83,471,942	40.66%	13,791,343	6.72%
312.00	Boiler Plant Equipment	1,091,953,161	-18.2%	1,290,702,396	430,944,377	39.47%	504,133,752	46.17%	446,204,432	40.86%	402,208,565	36.83%	43,995,866	4.03%
314.00	Turbogenerator Units	303,041,923	-15.4%	349,741,726	108,786,141	35.90%	126,836,287	41.85%	107,785,125	35.57%	96,100,917	31.71%	11,684,208	3.86%
315.00	Accessory Electric Equipment	144,581,471	-19.4%	172,696,014	67,267,210	46.53%	65,072,054	45.01%	62,321,558	43.10%	55,585,235	38.45%	6,736,323	4.66%
316.00	Miscellaneous Power Plant Equipment	25,222,863	-12.1%	28,264,453	11,455,994	45.42%	10,980,670	43.53%	11,290,994	44.76%	10,427,851	41.34%	863,142	3.42%
Total Steam Production Plant		**1,775,183,769**	**-17.8%**	**2,091,820,012**	**727,521,616**	**40.98%**	**812,832,259**	**45.79%**	**727,521,616**	**40.98%**	**650,450,218**	**36.64%**	**77,071,398**	**4.34%**
OTHER PRODUCTION														
Non-Solar														
341.00	Structures and Improvements	23,403,461	-14.5%	26,800,461	4,517,794	19.30%	5,425,906	23.18%	3,641,838	15.56%	3,393,754	14.50%	248,085	1.06%
342.00	Fuel Holders, Products and Accessories	19,977,187	-14.0%	22,782,789	3,821,601	19.13%	4,567,093	22.86%	2,937,436	14.70%	2,799,007	14.01%	138,429	0.69%
343.00	Prime Movers	202,005,134	-8.9%	220,075,339	45,871,980	22.71%	46,219,655	22.88%	45,865,404	22.71%	43,761,643	21.66%	2,103,761	1.04%
344.00	Generators and Devices	105,487,225	-9.3%	115,299,196	42,523,497	40.31%	36,389,469	34.50%	44,724,870	42.40%	42,075,079	39.89%	2,649,791	2.51%
345.00	Accessory Electric Equipment	13,809,819	-8.6%	15,000,272	5,672,963	41.08%	4,558,660	33.01%	5,680,821	41.14%	5,317,644	38.51%	363,177	2.63%
346.00	Miscellaneous Power Plant Equipment	15,307,160	-13.7%	17,398,936	3,234,180	21.13%	3,739,237	24.43%	2,791,645	18.24%	2,617,219	17.10%	174,426	1.14%
Total Non-Solar		**379,989,986**	**-9.8%**	**417,356,994**	**105,642,014**	**27.80%**	**100,900,020**	**26.55%**	**105,642,014**	**27.80%**	**99,964,346**	**26.31%**	**5,677,668**	**1.49%**
Solar														
344.00	Generators and Devices	170,320,932	-5.0%	178,836,979	26,892,332	15.79%	22,416,079	13.16%	26,892,332	15.79%	25,611,745	15.04%	1,280,587	0.75%
Total Solar		**170,320,932**	**-5.0%**	**178,836,979**	**26,892,332**	**15.79%**	**22,416,079**	**13.16%**	**26,892,332**	**15.79%**	**25,611,745**	**15.04%**	**1,280,587**	**0.75%**
Total Other Production Plant		**550,310,918**	**-8.3%**	**596,193,973**	**132,534,346**	**24.08%**	**123,316,099**	**22.41%**	**132,534,346**	**24.08%**	**125,576,091**	**22.82%**	**6,958,255**	**1.26%**
DISTRIBUTION PLANT														
360.RW	Rights-of-Way	7,865,073	0.0%	7,865,073	3,685,111	46.85%	2,967,754	37.73%	4,136,928	52.60%	4,136,928	52.60%	0	0.00%
361.00	Structures and Improvements	11,402,474	0.0%	11,402,474	2,440,911	21.41%	1,927,786	16.91%	2,687,255	23.57%	2,687,255	23.57%	0	0.00%
362.00	Station Equipment	157,067,530	0.0%	157,067,530	44,816,223	28.53%	38,291,794	24.38%	53,377,197	33.98%	53,377,197	33.98%	0	0.00%
364.00	Poles, Towers and Fixtures	222,006,967	0.0%	222,006,967	71,565,728	32.24%	53,853,971	24.26%	75,070,237	33.81%	75,070,237	33.81%	0	0.00%
365.00	Overhead Conductors and Devices	175,675,966	0.0%	175,675,966	59,385,788	33.80%	50,923,833	28.99%	70,985,744	40.41%	70,985,744	40.41%	0	0.00%
366.00	Underground Conduit	58,725,355	0.0%	58,725,355	23,125,320	39.38%	18,680,394	31.81%	26,039,706	44.34%	26,039,706	44.34%	0	0.00%
367.00	Underground Conductors and Devices	297,183,135	0.0%	297,183,135	119,413,016	40.18%	92,262,153	31.05%	128,609,675	43.28%	128,609,675	43.28%	0	0.00%
368.OH	Line Transformers - Overhead	103,657,922	0.0%	103,657,922	45,498,501	43.89%	31,691,984	30.57%	44,177,332	42.62%	44,177,332	42.62%	0	0.00%
368.UG	Line Transformers - Underground	172,890,932	0.0%	172,890,932	71,195,629	41.18%	52,540,781	30.39%	73,239,704	42.36%	73,239,704	42.36%	0	0.00%
369.OH	Services - Overhead	17,542,236	0.0%	17,542,236	8,133,240	46.36%	6,372,839	36.33%	8,883,477	50.64%	8,883,477	50.64%	0	0.00%
369.UG	Services - Underground	112,947,714	0.0%	112,947,714	35,019,387	31.00%	28,664,832	25.38%	39,957,605	35.38%	39,957,605	35.38%	0	0.00%
370.00	Meters	44,869,823	0.0%	44,869,823	(225,711)	-0.50%	8,648,279	19.27%	12,055,348	26.87%	12,055,348	26.87%	0	0.00%
373.00	Street Lighting and Signal Systems	11,778,362	0.0%	11,778,362	4,929,241	41.85%	3,992,908	33.90%	5,565,950	47.26%	5,565,950	47.26%	0	0.00%
Total Distribution Plant		**1,393,613,489**	**0.0%**	**1,393,613,489**	**488,982,384**	**35.09%**	**390,819,309**	**28.04%**	**544,786,159**	**39.09%**	**544,786,159**	**39.09%**	**0**	**0.00%**
GENERAL PLANT														
Depreciable														
390.00	Structures and Improvements	135,680,348	-5.0%	142,464,365	22,140,915	16.32%	23,121,989	17.04%	21,696,815	15.99%	21,570,039	15.90%	126,776	0.09%
392.C0	Transportation - Class 0	1,238,946	15.0%	1,053,104	537,462	43.38%	430,858	34.78%	404,302	32.63%	458,248	36.99%	(53,946)	-4.35%

Tucson Electric Power Company
Calculation of Depreciation Reserve Allocation

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392.C1	Transportation - Class 1	7,718,183	15.0%	6,560,456	3,370,156	43.67%	3,085,389	39.98%	2,895,214	37.51%	3,304,203	42.81%	(408,989)	-5.30%
392.C2	Transportation - Class 2	3,839,907	15.0%	3,263,921	1,471,770	38.33%	1,512,999	39.40%	1,419,742	36.97%	1,609,294	41.91%	(189,552)	-4.94%
392.C3	Transportation - Class 3	2,076,936	15.0%	1,765,396	1,040,386	50.09%	982,304	47.30%	921,757	44.38%	1,052,793	50.69%	(131,035)	-6.31%
392.C4	Transportation - Class 4	2,935,027	15.0%	2,494,773	748,506	25.50%	1,119,503	38.14%	1,050,500	35.79%	1,180,337	40.22%	(129,837)	-4.42%
392.C5	Transportation - Class 5	7,982,715	15.0%	6,785,308	2,758,719	34.56%	3,223,932	40.39%	3,025,218	37.90%	3,474,021	43.52%	(448,803)	-5.62%
392.C6	Transportation - Class 6	365,200	15.0%	310,420	71,788	19.66%	72,748	19.92%	68,264	18.69%	80,311	21.99%	(12,047)	-3.30%
392.C7	Transportation - Class 7	1,047,216	15.0%	890,134	431,484	41.20%	371,401	35.47%	348,508	33.28%	410,010	39.15%	(61,501)	-5.87%
392.C8	Transportation - Class 8	9,957,500	15.0%	8,463,875	3,320,461	33.35%	3,285,253	32.99%	3,082,759	30.96%	3,613,292	36.29%	(530,533)	-5.33%
392.C9	Transportation - Class 9	4,252,286	15.0%	3,614,443	1,578,200	37.11%	1,139,077	26.79%	1,068,867	25.14%	1,247,812	29.34%	(178,945)	-4.21%
396.00	Power Operatied Equipment	11,860,940	0.0%	11,860,940	2,437,035	20.55%	2,664,204	22.46%	2,499,990	21.08%	2,412,819	20.34%	87,170	0.73%
397.EM	EMS and SCADA Equipment	11,304,371	0.0%	11,304,371	3,197,149	28.28%	3,314,518	29.32%	3,110,221	27.51%	3,110,221	27.51%	0	0.00%
Total Depreciable		**200,259,575**	**-0.3%**	**200,831,505**	**43,104,031**	**21.52%**	**44,324,175**	**22.13%**	**41,592,158**	**20.77%**	**43,523,399**	**21.73%**	**(1,931,242)**	**-0.96%**
Amortizable														
391.00	Furniture and Office Equipment	23,964,411	0.0%	23,964,411	7,694,941	32.11%	7,698,753	32.13%	7,698,753	32.13%	7,698,753	32.13%	0	0.00%
391.20	Network and Data Equipment	29,359,636	0.0%	29,359,636	14,970,053	50.99%	14,913,970	50.80%	14,913,970	50.80%	14,913,970	50.80%	0	0.00%
393.00	Stores Equipment	1,852,479	0.0%	1,852,479	820,258	44.28%	840,197	45.36%	840,197	45.36%	840,197	45.36%	0	0.00%
394.00	Tools, Shop and Garage Equipment	6,934,368	0.0%	6,934,368	2,860,187	41.25%	2,858,589	41.22%	2,858,589	41.22%	2,858,589	41.22%	0	0.00%
395.00	Laboratory Equipment	5,091,270	0.0%	5,091,270	2,395,517	47.05%	2,395,826	47.06%	2,395,826	47.06%	2,395,826	47.06%	0	0.00%
397.20	Telecommunications Equipment	57,456,141	0.0%	57,456,141	18,113,523	31.53%	19,662,636	34.22%	19,662,636	34.22%	19,662,636	34.22%	0	0.00%
398.00	Miscellaneous Equipment	4,348,209	0.0%	4,348,209	1,818,966	41.83%	1,815,347	41.75%	1,815,347	41.75%	1,815,347	41.75%	0	0.00%
Total Amortizable		**129,006,514**	**0.0%**	**129,006,514**	**48,673,445**	**37.73%**	**50,185,318**	**38.90%**	**50,185,318**	**38.90%**	**50,185,318**	**38.90%**	**0**	**0.00%**
Total General Plant		**329,266,089**	**-0.2%**	**329,838,019**	**91,777,476**	**27.87%**	**94,509,493**	**28.70%**	**91,777,476**	**27.87%**	**93,708,717**	**28.46%**	**(1,931,242)**	**-0.59%**
SUBTOTAL		**4,048,374,265**	**-9.0%**	**4,411,465,493**	**1,440,815,822**	**35.59%**	**1,421,477,159**	**35.11%**	**1,496,619,597**	**36.97%**	**1,414,521,186**	**34.94%**	**82,098,411**	**2.03%**
NET SALVAGE														
108.02	Distribution	1,393,613,489	-15.0%	1,602,655,512	85,838,400	6.16%	21,546,273	1.55%	30,034,625	2.16%		0.00%	30,034,625	2.16%
Total Net Salvage		**1,393,613,489**	**-15.0%**	**1,602,655,512**	**85,838,400**	**6.16%**	**21,546,273**	**1.55%**	**30,034,625**	**2.16%**	**0**	**0.00%**	**30,034,625**	**2.16%**
TOTAL UTILITY		**4,048,374,265**	**-48.6%**	**6,014,121,006**	**1,526,654,221**	**37.71%**	**1,443,023,432**	**35.64%**	**1,526,654,221**	**37.71%**	**1,414,521,186**	**34.94%**	**112,133,036**	**2.77%**
STEAM PRODUCTION (by Unit)														
Four Corners														
310.00	Rights-of-Way	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
311.00	Structures and Improvements	2,982,777	-6.3%	3,171,952	1,813,087	60.79%	1,386,686	46.49%	1,909,591	64.02%	1,818,284	60.96%	91,307	3.06%
312.00	Boiler Plant Equipment	76,402,061	-6.3%	81,243,732	60,687,020	79.43%	43,813,191	57.35%	60,348,163	78.99%	57,866,410	75.74%	2,481,753	3.25%
314.00	Turbogenerator Units	12,359,480	-6.3%	13,137,310	8,806,344	71.25%	6,389,905	51.70%	8,829,293	71.44%	8,375,330	67.76%	453,963	3.67%
315.00	Accessory Electric Equipment	4,390,980	-6.3%	4,669,252	1,422,016	32.38%	1,201,366	27.36%	1,657,254	37.74%	1,550,168	35.30%	107,086	2.44%
316.00	Miscellaneous Power Plant Equipment	3,832,234	-6.1%	4,065,922	2,573,936	67.17%	1,858,755	48.50%	2,558,102	66.75%	2,439,226	63.65%	118,876	3.10%
Total Four Corners		**99,967,532**	**-6.3%**	**106,288,168**	**75,302,403**	**75.33%**	**54,649,901**	**54.67%**	**75,302,403**	**75.33%**	**72,049,418**	**72.07%**	**3,252,985**	**3.25%**
Four Corners Unit 4														
310.00	Rights-of-Way	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%

Tucson Electric Power Company
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311.00	Structures and Improvements	1,524,414	-6.0%	1,615,879	957,081	62.78%	706,782	46.36%	1,004,754	65.91%	959,414	62.94%	45,341	2.97%
312.00	Boiler Plant Equipment	39,609,538	-6.0%	41,986,110	32,129,841	81.12%	22,479,492	56.75%	31,956,649	80.68%	30,915,436	78.05%	1,041,213	2.63%
314.00	Turbogenerator Units	7,179,362	-6.0%	7,610,124	5,095,340	70.97%	3,585,427	49.94%	5,097,011	71.00%	4,836,928	67.37%	260,083	3.62%
315.00	Accessory Electric Equipment	2,274,836	-6.0%	2,411,326	782,000	34.38%	643,902	28.31%	915,365	40.24%	852,342	37.47%	63,023	2.77%
316.00	Miscellaneous Power Plant Equipment	1,929,161	-5.8%	2,041,052	1,331,723	69.03%	930,087	48.21%	1,322,204	68.54%	1,263,646	65.50%	58,558	3.04%
Total Four Corners Unit 4		**52,517,311**	**-6.0%**	**55,664,491**	**40,295,985**	**76.73%**	**28,345,690**	**53.97%**	**40,295,985**	**76.73%**	**38,827,767**	**73.93%**	**1,468,218**	**2.80%**
Four Corners Unit 5														
310.00	Rights-of-Way	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
311.00	Structures and Improvements	1,458,363	-6.7%	1,556,073	856,006	58.70%	679,904	46.62%	904,837	62.04%	858,870	58.89%	45,966	3.15%
312.00	Boiler Plant Equipment	36,792,523	-6.7%	39,257,622	28,557,180	77.62%	21,333,699	57.98%	28,391,514	77.17%	26,950,973	73.25%	1,440,540	3.92%
314.00	Turbogenerator Units	5,180,118	-6.7%	5,527,186	3,711,004	71.64%	2,804,478	54.14%	3,732,282	72.05%	3,538,401	68.31%	193,880	3.74%
315.00	Accessory Electric Equipment	2,116,144	-6.7%	2,257,926	640,016	30.24%	557,463	26.34%	741,889	35.06%	697,826	32.98%	44,063	2.08%
316.00	Miscellaneous Power Plant Equipment	1,903,073	-6.4%	2,024,870	1,242,213	65.27%	928,667	48.80%	1,235,898	64.94%	1,175,580	61.77%	60,318	3.17%
Total Four Corners Unit 5		**47,450,221**	**-6.7%**	**50,623,677**	**35,006,419**	**73.78%**	**26,304,212**	**55.44%**	**35,006,419**	**73.78%**	**33,221,651**	**70.01%**	**1,784,767**	**3.76%**
Navajo														
310.00	Rights-of-Way	12,229	-6.0%	12,963	12,671	103.62%	9,014	73.71%	11,457	93.69%	10,943	89.48%	514	4.21%
311.00	Structures and Improvements	18,655,156	-6.0%	19,773,337	13,989,522	74.99%	11,418,700	61.21%	13,563,269	72.71%	12,924,171	69.28%	639,098	3.43%
312.00	Boiler Plant Equipment	88,544,201	-5.9%	93,759,651	67,034,406	75.71%	58,764,504	66.37%	67,570,842	76.31%	64,261,410	72.58%	3,309,432	3.74%
314.00	Turbogenerator Units	20,255,526	-5.9%	21,444,383	16,002,717	79.00%	13,884,439	68.55%	15,851,479	78.26%	15,090,058	74.50%	761,421	3.76%
315.00	Accessory Electric Equipment	14,829,858	-5.9%	15,709,187	9,777,819	65.93%	8,366,375	56.42%	9,857,500	66.47%	9,396,746	63.36%	460,754	3.11%
316.00	Miscellaneous Power Plant Equipment	4,518,597	-5.9%	4,785,494	2,967,546	65.67%	2,412,911	53.40%	2,930,135	64.85%	2,798,421	61.93%	131,714	2.91%
Total Navajo		**146,815,567**	**-5.9%**	**155,485,014**	**109,784,682**	**74.78%**	**94,855,944**	**64.61%**	**109,784,682**	**74.78%**	**104,481,749**	**71.17%**	**5,302,933**	**3.61%**
Navajo Unit 1														
310.00	Rights-of-Way	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
311.00	Structures and Improvements	3,190,563	-5.0%	3,350,091	3,081,399	96.58%	2,935,896	92.02%	2,732,415	85.64%	2,607,266	81.72%	125,149	3.92%
312.00	Boiler Plant Equipment	27,198,582	-5.0%	28,558,511	20,390,194	74.97%	22,456,967	82.57%	20,900,519	76.84%	19,943,243	73.32%	957,276	3.52%
314.00	Turbogenerator Units	6,860,989	-5.0%	7,204,038	5,372,911	78.31%	5,658,353	82.47%	5,266,184	76.76%	5,019,772	73.16%	246,412	3.59%
315.00	Accessory Electric Equipment	3,544,300	-5.0%	3,721,515	2,315,538	65.33%	2,485,976	70.14%	2,313,678	65.28%	2,205,622	62.23%	108,056	3.05%
316.00	Miscellaneous Power Plant Equipment	471,227	-4.9%	494,317	458,551	97.31%	436,017	92.53%	405,798	86.12%	387,582	82.25%	18,216	3.87%
Total Navajo Unit 1		**41,265,661**	**-5.0%**	**43,328,473**	**31,618,592**	**76.62%**	**33,973,209**	**82.33%**	**31,618,592**	**76.62%**	**30,163,484**	**73.10%**	**1,455,108**	**3.53%**
Navajo Unit 2														
310.00	Rights-of-Way	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
311.00	Structures and Improvements	1,802,685	-6.6%	1,921,662	1,519,996	84.32%	1,166,605	64.71%	1,509,303	83.73%	1,432,989	79.49%	76,314	4.23%
312.00	Boiler Plant Equipment	26,882,286	-6.6%	28,656,517	21,334,917	79.36%	16,484,126	61.32%	21,326,441	79.33%	20,203,004	75.15%	1,123,437	4.18%
314.00	Turbogenerator Units	6,926,050	-6.6%	7,383,169	5,347,290	77.21%	4,134,480	59.69%	5,349,010	77.23%	5,080,922	73.36%	268,088	3.87%
315.00	Accessory Electric Equipment	3,172,330	-6.6%	3,381,704	2,305,054	72.66%	1,803,196	56.84%	2,332,896	73.54%	2,213,989	69.79%	118,908	3.75%
316.00	Miscellaneous Power Plant Equipment	515,874	-6.4%	548,890	478,584	92.77%	361,885	70.15%	468,191	90.76%	446,111	86.48%	22,081	4.28%
Total Navajo Unit 2		**39,299,225**	**-6.6%**	**41,891,942**	**30,985,841**	**78.85%**	**23,950,293**	**60.94%**	**30,985,841**	**78.85%**	**29,377,014**	**74.75%**	**1,608,827**	**4.09%**
Navajo Unit 3														
310.00	Rights-of-Way	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%

Tucson Electric Power Company
Calculation of Depreciation Reserve Allocation

Account	Description	12/31/14 Investment	Future Net Salvage Percent	Total to be Recovered	Book Reserve Amount	Book Reserve Percent	Theoretical Reserve Amount	Theoretical Reserve Percent	Redistributed Reserve Amount	Redistributed Reserve Percent	Investment Reserve Amount	Investment Reserve Percent	Salvage Reserve Amount	Salvage Reserve Percent
311.00	Structures and Improvements	3,681,511	-6.0%	3,902,402	3,289,429	89.35%	2,533,202	68.81%	3,242,242	88.07%	3,095,153	84.07%	147,089	4.00%
312.00	Boiler Plant Equipment	27,718,514	-6.0%	29,381,625	21,206,074	76.51%	16,659,767	60.10%	21,322,809	76.93%	20,263,915	73.11%	1,058,895	3.82%
314.00	Turbogenerator Units	6,178,944	-6.0%	6,549,681	5,218,613	84.46%	4,029,105	65.21%	5,156,845	83.46%	4,913,913	79.53%	242,932	3.93%
315.00	Accessory Electric Equipment	5,139,872	-6.0%	5,448,264	4,138,011	80.51%	3,234,223	62.92%	4,139,477	80.54%	3,963,645	77.12%	175,832	3.42%
316.00	Miscellaneous Power Plant Equipment	549,362	-5.8%	581,225	503,918	91.73%	386,493	70.35%	494,672	90.04%	475,548	86.56%	19,124	3.48%
Total Navajo Unit 3		**43,268,203**	**-6.0%**	**45,863,196**	**34,356,045**	**79.40%**	**26,842,790**	**62.04%**	**34,356,045**	**79.40%**	**32,712,174**	**75.60%**	**1,643,871**	**3.80%**
Navajo Common														
310.00	Rights-of-Way	12,229	-6.0%	12,963	12,671	103.62%	9,014	73.71%	11,457	93.69%	10,943	89.48%	514	4.21%
311.00	Structures and Improvements	9,980,397	-6.2%	10,599,182	6,098,698	61.11%	4,782,996	47.92%	6,079,309	60.91%	5,788,763	58.00%	290,546	2.91%
312.00	Boiler Plant Equipment	6,744,819	-6.2%	7,162,998	4,103,220	60.84%	3,163,645	46.90%	4,021,073	59.62%	3,851,248	57.10%	169,825	2.52%
314.00	Turbogenerator Units	289,543	-6.2%	307,495	63,903	22.07%	62,501	21.59%	79,441	27.44%	75,451	26.06%	3,990	1.38%
315.00	Accessory Electric Equipment	2,973,356	-6.2%	3,157,704	1,019,217	34.28%	842,980	28.35%	1,071,449	36.04%	1,013,491	34.09%	57,958	1.95%
316.00	Miscellaneous Power Plant Equipment	2,982,134	-6.0%	3,161,062	1,526,493	51.19%	1,228,515	41.20%	1,561,474	52.36%	1,489,181	49.94%	72,293	2.42%
Total Navajo Common		**22,982,478**	**-6.2%**	**24,401,403**	**12,824,203**	**55.80%**	**10,089,652**	**43.90%**	**12,824,203**	**55.80%**	**12,229,077**	**53.21%**	**595,126**	**2.59%**
San Juan														
310.00	Rights-of-Way	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
311.00	Structures and Improvements	14,437,744	-9.6%	15,822,118	3,437,723	23.81%	8,972,935	62.15%	1,090,514	7.55%	1,006,420	6.97%	84,094	0.58%
312.00	Boiler Plant Equipment	154,506,908	-11.7%	172,659,253	6,056,700	3.92%	85,966,325	55.64%	10,447,810	6.76%	9,578,395	6.20%	869,415	0.56%
314.00	Turbogenerator Units	44,295,673	-9.7%	48,592,353	6,542,378	14.77%	27,386,524	61.83%	3,328,387	7.51%	3,068,982	6.93%	259,405	0.59%
315.00	Accessory Electric Equipment	10,063,526	-9.7%	11,039,688	(132,385)	-1.32%	5,660,586	56.25%	687,952	6.84%	634,267	6.30%	53,685	0.53%
316.00	Miscellaneous Power Plant Equipment	2,009,555	-9.3%	2,195,771	(208,748)	-10.39%	1,160,207	57.73%	141,004	7.02%	129,811	6.46%	11,194	0.56%
Total San Juan		**225,313,406**	**-11.1%**	**250,309,183**	**15,695,668**	**6.97%**	**129,146,577**	**57.32%**	**15,695,668**	**6.97%**	**14,417,875**	**6.40%**	**1,277,794**	**0.57%**
San Juan Unit 1														
310.00	Rights-of-Way	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
311.00	Structures and Improvements	14,268,404	-9.7%	15,652,439	3,436,921	24.09%	8,966,435	62.84%	1,089,724	7.64%	1,005,632	7.05%	84,093	0.59%
312.00	Boiler Plant Equipment	146,453,029	-9.7%	160,658,973	1,499,790	1.02%	81,149,969	55.41%	9,862,460	6.73%	9,179,792	6.27%	682,668	0.47%
314.00	Turbogenerator Units	44,295,673	-9.7%	48,592,353	6,542,378	14.77%	27,386,524	61.83%	3,328,387	7.51%	3,068,982	6.93%	259,405	0.59%
315.00	Accessory Electric Equipment	10,063,526	-9.7%	11,039,688	(132,385)	-1.32%	5,660,586	56.25%	687,952	6.84%	634,267	6.30%	53,685	0.53%
316.00	Miscellaneous Power Plant Equipment	1,960,172	-9.5%	2,146,388	(209,009)	-10.66%	1,158,316	59.09%	140,774	7.18%	129,581	6.61%	11,194	0.57%
Total San Juan Unit 1		**217,040,804**	**-9.7%**	**238,089,842**	**11,137,695**	**5.13%**	**124,321,829**	**57.28%**	**15,109,298**	**6.96%**	**14,018,253**	**6.46%**	**1,091,045**	**0.50%**
San Juan Common														
310.00	Rights-of-Way	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
311.00	Structures and Improvements	169,340	-0.2%	169,679	803	0.47%	6,501	3.84%	790	0.47%	788	0.47%	2	0.00%
312.00	Boiler Plant Equipment	8,053,879	-49.0%	12,000,280	4,556,910	56.58%	4,816,355	59.80%	585,350	7.27%	398,603	4.95%	186,747	2.32%
314.00	Turbogenerator Units	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
315.00	Accessory Electric Equipment	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
316.00	Miscellaneous Power Plant Equipment	49,383	0.0%	49,383	261	0.53%	1,892	3.83%	230	0.47%	230	0.47%	0	0.00%
Total San Juan Common		**8,272,602**	**-47.7%**	**12,219,341**	**4,557,973**	**55.10%**	**4,824,748**	**58.32%**	**586,370**	**7.09%**	**399,621**	**4.83%**	**186,748**	**2.26%**
Springerville														
310.00	Rights-of-Way	5,094,433	0.0%	5,094,433	3,681,571	72.27%	2,866,675	56.27%	2,644,766	51.91%	2,644,766	51.91%	0	0.00%

Tucson Electric Power Company
Calculation of Depreciation Reserve Allocation

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311.00	Structures and Improvements	141,726,641	-17.8%	166,949,200	69,753,908	49.22%	67,443,147	47.59%	67,999,520	47.98%	58,069,236	40.97%	9,930,284	7.01%
312.00	Boiler Plant Equipment	641,687,365	-18.3%	759,230,926	245,587,975	38.27%	248,338,250	38.70%	245,667,845	38.28%	223,625,040	34.85%	22,042,804	3.44%
314.00	Turbogenerator Units	173,649,915	-6.6%	185,073,607	50,485,589	29.07%	52,076,344	29.99%	54,676,760	31.49%	52,916,045	30.47%	1,760,716	1.01%
315.00	Accessory Electric Equipment	75,864,618	-8.8%	82,540,502	36,828,958	48.55%	34,122,060	44.98%	35,557,418	46.87%	33,501,347	44.16%	2,056,071	2.71%
316.00	Miscellaneous Power Plant Equipment	12,528,984	-9.3%	13,697,132	5,054,564	40.34%	4,668,322	37.26%	4,846,255	38.68%	4,496,598	35.89%	349,657	2.79%
Total Springerville		**1,050,551,956**	**-15.4%**	**1,212,585,801**	**411,392,565**	**39.16%**	**409,514,798**	**38.98%**	**411,392,565**	**39.16%**	**375,253,032**	**35.72%**	**36,139,532**	**3.44%**
Springerville Unit 1														
310.00	Rights-of-Way	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
311.00	Structures and Improvements	20,076,015	-5.5%	21,180,196	8,646,215	43.07%	7,772,710	38.72%	8,562,949	42.65%	8,181,475	40.75%	381,474	1.90%
312.00	Boiler Plant Equipment	185,682,490	-5.5%	195,895,027	82,449,685	44.40%	76,209,273	41.04%	83,957,350	45.22%	80,313,040	43.25%	3,644,310	1.96%
314.00	Turbogenerator Units	49,547,312	-5.5%	52,272,414	24,720,176	49.89%	20,501,134	41.38%	22,585,452	45.58%	21,608,560	43.61%	976,892	1.97%
315.00	Accessory Electric Equipment	21,214,167	-5.5%	22,380,946	10,429,780	49.16%	10,138,966	47.79%	11,169,779	52.65%	10,788,591	50.86%	381,188	1.80%
316.00	Miscellaneous Power Plant Equipment	3,277,742	-5.1%	3,444,907	1,342,432	40.96%	1,191,608	36.35%	1,312,757	40.05%	1,255,155	38.29%	57,602	1.76%
Total Springerville Unit 1		**279,797,726**	**-5.5%**	**295,173,490**	**127,588,287**	**45.60%**	**115,813,690**	**41.39%**	**127,588,287**	**45.60%**	**122,146,821**	**43.66%**	**5,441,466**	**1.94%**
Springerville Unit 1 Common														
310.00	Rights-of-Way	1,143,496	0.0%	1,143,496	878,769	76.85%	472,348	41.31%	501,934	43.89%	501,934	43.89%	0	0.00%
311.00	Structures and Improvements	52,492,826	-16.8%	61,311,621	26,956,787	51.35%	24,529,260	46.73%	26,065,636	49.66%	22,869,968	43.57%	3,195,668	6.09%
312.00	Boiler Plant Equipment	14,854,799	-16.8%	17,350,405	7,017,428	47.24%	7,102,335	47.81%	7,547,186	50.81%	6,682,908	44.99%	864,278	5.82%
314.00	Turbogenerator Units	1,264,322	-16.8%	1,476,728	677,581	53.59%	628,652	49.72%	668,027	52.84%	596,152	47.15%	71,875	5.68%
315.00	Accessory Electric Equipment	9,627,097	-16.8%	11,244,449	4,747,620	49.32%	5,063,206	52.59%	5,380,337	55.89%	4,895,266	50.85%	485,071	5.04%
316.00	Miscellaneous Power Plant Equipment	1,959,012	-16.4%	2,280,290	968,707	49.45%	1,019,892	52.06%	1,083,772	55.32%	982,614	50.16%	101,159	5.16%
Total Springerville Unit 1 Common		**81,341,552**	**-16.6%**	**94,806,989**	**41,246,892**	**50.71%**	**38,815,693**	**47.72%**	**41,246,892**	**50.71%**	**36,528,841**	**44.91%**	**4,718,051**	**5.80%**
Springerville Unit 2														
310.00	Rights-of-Way	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
311.00	Structures and Improvements	36,540,030	-6.7%	38,988,212	11,419,075	31.25%	10,347,690	28.32%	10,528,415	28.81%	10,256,607	28.07%	271,808	0.74%
312.00	Boiler Plant Equipment	295,922,545	-6.7%	315,749,356	90,766,387	30.67%	86,660,209	29.28%	88,173,753	29.80%	87,091,367	29.43%	1,082,385	0.37%
314.00	Turbogenerator Units	122,055,348	-6.7%	130,233,056	24,457,076	20.04%	30,283,382	24.81%	30,812,289	25.24%	30,256,387	24.79%	555,902	0.46%
315.00	Accessory Electric Equipment	42,346,939	-6.7%	45,184,184	19,274,032	45.51%	16,392,415	38.71%	16,678,713	39.39%	16,083,619	37.98%	595,094	1.41%
316.00	Miscellaneous Power Plant Equipment	6,624,669	-6.3%	7,042,023	2,247,196	33.92%	1,936,771	29.24%	1,970,597	29.75%	1,902,962	28.73%	67,635	1.02%
Total Springerville Unit 2		**503,489,531**	**-6.7%**	**537,196,831**	**148,163,767**	**29.43%**	**145,620,467**	**28.92%**	**148,163,767**	**29.43%**	**145,590,942**	**28.92%**	**2,572,824**	**0.51%**
Springerville Unit 2 Common (Leasehold Imp.)														
310.00	Rights-of-Way	2,280,838	0.0%	2,280,838	1,997,938	87.60%	1,638,561	71.84%	1,509,624	66.19%	1,509,624	66.19%	0	0.00%
311.00	Structures and Improvements	32,617,770	-39.4%	45,469,171	22,731,831	69.69%	24,793,488	76.01%	22,842,521	70.03%	16,761,186	51.39%	6,081,335	18.64%
312.00	Boiler Plant Equipment	6,282,729	-39.4%	8,758,124	3,192,901	50.82%	3,968,612	63.17%	3,656,327	58.20%	2,574,121	40.97%	1,082,206	17.23%
314.00	Turbogenerator Units	782,933	-39.4%	1,091,409	630,756	80.56%	663,177	84.70%	610,992	78.04%	454,946	58.11%	156,046	19.93%
315.00	Accessory Electric Equipment	2,676,415	-39.4%	3,730,923	2,377,526	88.83%	2,527,473	94.44%	2,328,589	87.00%	1,733,871	64.78%	594,718	22.22%
316.00	Miscellaneous Power Plant Equipment	667,561	-39.3%	929,912	496,229	74.33%	520,051	77.90%	479,129	71.77%	355,867	53.31%	123,262	18.46%
Total Springerville Unit 2 Common		**45,308,246**	**-37.4%**	**62,260,377**	**31,427,182**	**69.36%**	**34,111,361**	**75.29%**	**31,427,182**	**69.36%**	**23,389,615**	**51.62%**	**8,037,567**	**17.74%**
Springerville Coal Handling														
310.00	Rights-of-Way	1,670,099	0.0%	1,670,099	804,864	48.19%	755,766	45.25%	633,208	37.91%	633,208	37.91%	0	0.00%

Tucson Electric Power Company
Calculation of Depreciation Reserve Allocation

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311.00	Structures and Improvements	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
312.00	Boiler Plant Equipment	138,944,802	-59.4%	221,478,014	62,161,574	44.74%	74,397,821	53.54%	62,333,229	44.86%	46,963,604	33.80%	15,369,625	11.06%
314.00	Turbogenerator Units	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
315.00	Accessory Electric Equipment	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
316.00	Miscellaneous Power Plant Equipment	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
Total Springerville Coal Handling		**140,614,901**	**-58.7%**	**223,148,113**	**62,966,438**	**44.78%**	**75,153,587**	**53.45%**	**62,966,438**	**44.78%**	**47,596,813**	**33.85%**	**15,369,625**	**10.93%**
Sundt														
310.00	Rights-of-Way	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
311.00	Structures and Improvements	27,475,371	-44.1%	39,591,421	16,379,412	59.61%	13,712,340	49.91%	12,700,391	46.22%	9,653,831	35.14%	3,046,560	11.09%
312.00	Boiler Plant Equipment	130,812,626	-40.5%	183,808,834	51,578,275	39.43%	67,251,482	51.41%	62,169,771	47.53%	46,877,310	35.84%	15,292,462	11.69%
314.00	Turbogenerator Units	52,481,329	-55.3%	81,494,073	26,949,112	51.35%	27,099,075	51.64%	25,099,206	47.83%	16,650,503	31.73%	8,448,703	16.10%
315.00	Accessory Electric Equipment	39,432,489	-49.0%	58,737,385	19,370,802	49.12%	15,721,668	39.87%	14,561,433	36.93%	10,502,706	26.63%	4,058,727	10.29%
316.00	Miscellaneous Power Plant Equipment	2,333,493	-50.9%	3,520,133	1,068,696	45.80%	880,474	37.73%	815,497	34.95%	563,795	24.16%	251,702	10.79%
Total Sundt		**252,535,308**	**-45.4%**	**367,151,846**	**115,346,298**	**45.68%**	**124,665,039**	**49.37%**	**115,346,298**	**45.68%**	**84,248,144**	**33.36%**	**31,098,154**	**12.31%**
Sundt Unit 1														
310.00	Rights-of-Way	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
311.00	Structures and Improvements	3,926,062	-58.6%	6,226,734	2,175,028	55.40%	2,300,086	58.59%	2,130,344	54.26%	1,390,205	35.41%	740,139	18.85%
312.00	Boiler Plant Equipment	13,782,181	-58.7%	21,872,321	10,318,349	74.87%	9,503,713	68.96%	8,802,354	63.87%	5,615,586	40.75%	3,186,768	23.12%
314.00	Turbogenerator Units	10,237,507	-58.7%	16,246,924	6,554,053	64.02%	5,975,069	58.36%	5,534,119	54.06%	3,554,213	34.72%	1,979,905	19.34%
315.00	Accessory Electric Equipment	6,536,315	-58.7%	10,373,132	2,644,455	40.46%	2,066,066	31.61%	1,913,594	29.28%	1,169,940	17.90%	743,654	11.38%
316.00	Miscellaneous Power Plant Equipment	490,578	-58.6%	778,057	230,468	46.98%	186,279	37.97%	172,532	35.17%	111,390	22.71%	61,142	12.46%
Total Sundt Unit 1		**34,972,643**	**-58.7%**	**55,497,168**	**21,922,353**	**62.68%**	**20,031,215**	**57.28%**	**18,552,942**	**53.05%**	**11,841,334**	**33.86%**	**6,711,608**	**19.19%**
Sundt Unit 2														
310.00	Rights-of-Way	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
311.00	Structures and Improvements	2,812,689	-66.3%	4,677,502	1,133,428	40.30%	1,319,600	46.92%	1,222,216	43.45%	740,010	26.31%	482,206	17.14%
312.00	Boiler Plant Equipment	14,371,609	-66.3%	23,899,986	9,423,263	65.57%	9,953,568	69.26%	9,219,010	64.15%	5,985,800	41.65%	3,233,210	22.50%
314.00	Turbogenerator Units	8,451,923	-66.2%	14,047,096	5,713,503	67.60%	6,360,328	75.25%	5,890,945	69.70%	3,781,030	44.74%	2,109,915	24.96%
315.00	Accessory Electric Equipment	6,205,700	-66.4%	10,326,285	1,836,537	29.59%	1,727,237	27.83%	1,599,770	25.78%	973,375	15.69%	626,395	10.09%
316.00	Miscellaneous Power Plant Equipment	383,824	-66.2%	637,915	148,170	38.60%	134,882	35.14%	124,928	32.55%	76,244	19.86%	48,684	12.68%
Total Sundt Unit 2		**32,225,745**	**-66.3%**	**53,588,784**	**18,254,901**	**56.65%**	**19,495,615**	**60.50%**	**18,056,869**	**56.03%**	**11,556,460**	**35.86%**	**6,500,409**	**20.17%**
Sundt Unit 3														
310.00	Rights-of-Way	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
311.00	Structures and Improvements	2,762,012	-75.7%	4,852,855	1,386,818	50.21%	1,676,755	60.71%	1,553,013	56.23%	932,234	33.75%	620,779	22.48%
312.00	Boiler Plant Equipment	11,980,831	-75.7%	21,050,320	6,673,757	55.70%	8,103,293	67.64%	7,505,283	62.64%	4,653,440	38.84%	2,851,843	23.80%
314.00	Turbogenerator Units	14,830,615	-75.7%	26,057,391	8,326,645	56.14%	9,327,567	62.89%	8,639,207	58.25%	5,239,200	35.33%	3,400,007	22.93%
315.00	Accessory Electric Equipment	6,140,139	-75.7%	10,788,224	4,200,198	68.41%	4,059,051	66.11%	3,759,499	61.23%	2,265,197	36.89%	1,494,302	24.34%
316.00	Miscellaneous Power Plant Equipment	404,717	-75.5%	710,278	182,169	45.01%	184,767	45.65%	171,131	42.28%	97,921	24.19%	73,211	18.09%
Total Sundt Unit 3		**36,118,314**	**-75.7%**	**63,459,068**	**20,769,587**	**57.50%**	**23,351,432**	**64.65%**	**21,628,133**	**59.88%**	**13,187,992**	**36.51%**	**8,440,141**	**23.37%**
Sundt Unit 4														
310.00	Rights-of-Way	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%

Tucson Electric Power Company
Calculation of Depreciation Reserve Allocation

Account	Description	12/31/14 Investment	Future Net Salvage Percent	Total to be Recovered	Book Reserve Amount	Book Reserve Percent	Theoretical Reserve Amount	Theoretical Reserve Percent	Redistributed Reserve Amount	Redistributed Reserve Percent	Investment Reserve Amount	Investment Reserve Percent	Salvage Reserve Amount	Salvage Reserve Percent
311.00	Structures and Improvements	17,974,608	-32.6%	23,834,330	11,684,139	65.00%	8,415,899	46.82%	7,794,818	43.37%	6,591,382	36.67%	1,203,436	6.70%
312.00	Boiler Plant Equipment	80,576,055	-32.6%	106,843,849	25,148,847	31.21%	39,547,619	49.08%	36,629,066	45.46%	30,608,481	37.99%	6,020,585	7.47%
314.00	Turbogenerator Units	18,961,284	-32.6%	25,142,663	6,354,911	33.52%	5,436,112	28.67%	5,034,935	26.55%	4,076,060	21.50%	958,875	5.06%
315.00	Accessory Electric Equipment	20,550,335	-32.6%	27,249,744	10,689,612	52.02%	7,869,313	38.29%	7,288,570	35.47%	6,094,193	29.65%	1,194,377	5.81%
316.00	Miscellaneous Power Plant Equipment	1,054,374	-32.2%	1,393,882	507,889	48.17%	374,546	35.52%	346,905	32.90%	278,240	26.39%	68,665	6.51%
Total Sundt Unit 4		**139,116,656**	**-32.6%**	**184,464,468**	**54,385,398**	**39.09%**	**61,643,488**	**44.31%**	**57,094,295**	**41.04%**	**47,648,356**	**34.25%**	**9,445,939**	**6.79%**
Sundt Solar Booster (Areva)														
310.00	Rights-of-Way	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
311.00	Structures and Improvements	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
312.00	Boiler Plant Equipment	10,101,950	-0.4%	10,142,358	14,059	0.14%	143,289	1.42%	14,059	0.14%	14,003	0.14%	56	0.00%
314.00	Turbogenerator Units	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
315.00	Accessory Electric Equipment	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
316.00	Miscellaneous Power Plant Equipment	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
Total Sundt Solar Booster (Areva)		**10,101,950**	**-0.4%**	**10,142,358**	**14,059**	**0.14%**	**143,289**	**1.42%**	**14,059**	**0.14%**	**14,003**	**0.14%**	**56**	**0.00%**
OTHER PRODUCTION (by Unit)														
DeMoss Petrie Gas Unit 1														
341.00	Structures and Improvements	761,988	-9.0%	830,567	154,938	20.33%	152,019	19.95%	176,938	23.22%	161,449	21.19%	15,488	2.03%
342.00	Fuel Holders, Products and Accessories	750,386	-9.0%	817,921	261,338	34.83%	231,033	30.79%	268,903	35.84%	255,266	34.02%	13,637	1.82%
343.00	Prime Movers	76,766	-9.0%	83,675	8,524	11.10%	12,723	16.57%	14,809	19.29%	10,802	14.07%	4,007	5.22%
344.00	Generators and Devices	30,772,866	-9.0%	33,542,424	11,025,994	35.83%	9,399,288	30.54%	10,939,994	35.55%	10,384,930	33.75%	555,064	1.80%
345.00	Accessory Electric Equipment	861,492	-9.0%	939,026	268,405	31.16%	270,764	31.43%	315,147	36.58%	277,783	32.24%	37,364	4.34%
346.00	Miscellaneous Power Plant Equipment	376,605	-9.0%	410,499	115,469	30.66%	102,136	27.12%	118,877	31.57%	113,109	30.03%	5,769	1.53%
Total DeMoss Petrie Gas Unit 1		**33,600,103**	**-9.0%**	**36,624,112**	**11,834,668**	**35.22%**	**10,167,964**	**30.26%**	**11,834,668**	**35.22%**	**11,203,339**	**33.34%**	**631,329**	**1.88%**
Gila River														
341.00	Structures and Improvements	8,508,950	-8.4%	9,222,744	2,126,825	25.00%	2,132,690	25.06%	2,085,222	24.51%	1,995,428	23.45%	89,794	1.06%
342.00	Fuel Holders, Products and Accessories	6,783,045	-8.4%	7,352,642	1,695,243	24.99%	1,739,367	25.64%	1,695,857	25.00%	1,622,830	23.92%	73,027	1.08%
343.00	Prime Movers	188,744,730	-8.3%	204,417,716	45,163,873	23.93%	44,747,359	23.71%	44,920,085	23.80%	42,985,728	22.77%	1,934,358	1.02%
344.00	Generators and Devices	32,783,434	-8.3%	35,504,459	8,295,028	25.30%	8,494,355	25.91%	8,534,905	26.03%	8,167,373	24.91%	367,532	1.12%
345.00	Accessory Electric Equipment	9,030,698	-8.3%	9,782,416	2,242,691	24.83%	2,298,438	25.45%	2,292,546	25.39%	2,193,824	24.29%	98,722	1.09%
346.00	Miscellaneous Power Plant Equipment	6,799,960	-8.4%	7,371,021	1,679,659	24.70%	1,717,914	25.26%	1,674,704	24.63%	1,602,587	23.57%	72,116	1.06%
Total Gila River		**252,650,817**	**-8.3%**	**273,650,999**	**61,203,319**	**24.22%**	**61,130,123**	**24.20%**	**61,203,319**	**24.22%**	**58,567,769**	**23.18%**	**2,635,550**	**1.04%**
Gila River Unit 3														
341.00	Structures and Improvements	957,417	-8.3%	1,036,883	259,052	27.06%	243,633	25.45%	244,796	25.57%	234,255	24.47%	10,541	1.10%
342.00	Fuel Holders, Products and Accessories	178,424	-8.3%	193,233	40,583	22.75%	41,504	23.26%	41,702	23.37%	39,907	22.37%	1,796	1.01%
343.00	Prime Movers	181,571,712	-8.3%	196,642,164	43,892,641	24.17%	43,407,520	23.91%	43,614,738	24.02%	41,736,592	22.99%	1,878,147	1.03%
344.00	Generators and Devices	32,783,434	-8.3%	35,504,459	8,295,028	25.30%	8,494,355	25.91%	8,534,905	26.03%	8,167,373	24.91%	367,532	1.12%
345.00	Accessory Electric Equipment	6,860,554	-8.3%	7,429,980	1,703,384	24.83%	1,745,799	25.45%	1,754,133	25.57%	1,678,596	24.47%	75,537	1.10%
346.00	Miscellaneous Power Plant Equipment	135,558	-8.3%	146,809	32,986	24.33%	33,242	24.52%	33,400	24.64%	31,962	23.58%	1,438	1.06%
Total Gila River Unit 3		**222,487,099**	**-8.3%**	**240,953,528**	**54,223,675**	**24.37%**	**53,966,052**	**24.26%**	**54,223,675**	**24.37%**	**51,888,684**	**23.32%**	**2,334,991**	**1.05%**

Tucson Electric Power Company
Calculation of Depreciation Reserve Allocation

Account	Description	12/31/14 Investment	Future Net Salvage Percent	Total to be Recovered	Book Reserve Amount	Book Reserve Percent	Theoretical Reserve Amount	Theoretical Reserve Percent	Redistributed Reserve Amount	Redistributed Reserve Percent	Investment Reserve Amount	Investment Reserve Percent	Salvage Reserve Amount	Salvage Reserve Percent
Gila River Common														
341.00	Structures and Improvements	7,551,533	-8.4%	8,185,862	1,867,772	24.73%	1,889,057	25.02%	1,840,426	24.37%	1,761,174	23.32%	79,253	1.05%
342.00	Fuel Holders, Products and Accessories	6,604,621	-8.4%	7,159,409	1,654,660	25.05%	1,697,863	25.71%	1,654,154	25.05%	1,582,923	23.97%	71,232	1.08%
343.00	Prime Movers	7,173,018	-8.4%	7,775,552	1,271,232	17.72%	1,339,839	18.68%	1,305,347	18.20%	1,249,136	17.41%	56,211	0.78%
344.00	Generators and Devices	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
345.00	Accessory Electric Equipment	2,170,144	-8.4%	2,352,436	539,307	24.85%	552,639	25.47%	538,413	24.81%	515,227	23.74%	23,185	1.07%
346.00	Miscellaneous Power Plant Equipment	6,664,402	-8.4%	7,224,212	1,646,673	24.71%	1,684,672	25.28%	1,641,303	24.63%	1,570,625	23.57%	70,678	1.06%
Total Gila River Common		**30,163,718**	**-8.4%**	**32,697,470**	**6,979,644**	**23.14%**	**7,164,070**	**23.75%**	**6,979,644**	**23.14%**	**6,679,085**	**22.14%**	**300,559**	**1.00%**
Luna														
341.00	Structures and Improvements	13,232,832	-18.8%	15,720,604	1,357,037	10.26%	2,594,010	19.60%	533,012	4.03%	486,325	3.68%	46,687	0.35%
342.00	Fuel Holders, Products and Accessories	11,352,383	-18.8%	13,486,631	1,178,720	10.38%	2,268,599	19.98%	466,147	4.11%	425,317	3.75%	40,830	0.36%
343.00	Prime Movers	11,151,074	-18.8%	13,247,476	(115,314)	-1.03%	1,019,584	9.14%	209,502	1.88%	158,063	1.42%	51,439	0.46%
344.00	Generators and Devices	9,486,694	-18.8%	11,270,192	(1,277,620)	-13.47%	1,829,905	19.29%	376,005	3.96%	283,805	2.99%	92,200	0.97%
345.00	Accessory Electric Equipment	9,647	-18.8%	11,461	114	1.18%	138	1.43%	28	0.29%	26	0.27%	2	0.03%
346.00	Miscellaneous Power Plant Equipment	7,424,592	-18.8%	8,820,415	744,049	10.02%	1,471,160	19.81%	302,291	4.07%	275,813	3.71%	26,478	0.36%
Total Luna		**52,657,222**	**-18.8%**	**62,556,780**	**1,886,985**	**3.58%**	**9,183,395**	**17.44%**	**1,886,985**	**3.58%**	**1,629,348**	**3.09%**	**257,637**	**0.49%**
North Loop Gas														
341.00	Structures and Improvements	888,601	-14.2%	1,015,217	867,104	97.58%	540,449	60.82%	835,215	93.99%	739,338	83.20%	95,877	10.79%
342.00	Fuel Holders, Products and Accessories	303,037	-5.7%	320,310	104,139	34.37%	91,403	30.16%	104,311	34.42%	101,077	33.35%	3,234	1.07%
343.00	Prime Movers	1,890,946	-15.4%	2,181,810	675,327	35.71%	377,852	19.98%	615,416	32.55%	503,480	26.63%	111,936	5.92%
344.00	Generators and Devices	24,062,187	-9.8%	26,419,987	15,675,191	65.14%	11,363,917	47.23%	15,866,542	65.94%	14,413,679	59.90%	1,452,863	6.04%
345.00	Accessory Electric Equipment	2,829,171	-11.9%	3,165,341	2,090,869	73.90%	1,355,150	47.90%	1,995,222	70.52%	1,789,250	63.24%	205,972	7.28%
346.00	Miscellaneous Power Plant Equipment	656,253	-13.7%	746,176	639,873	97.50%	412,780	62.90%	635,797	96.88%	566,911	86.39%	68,886	10.50%
Total North Loop Gas		**30,630,195**	**-10.5%**	**33,848,841**	**20,052,503**	**65.47%**	**14,141,551**	**46.17%**	**20,052,503**	**65.47%**	**18,113,734**	**59.14%**	**1,938,768**	**6.33%**
North Loop Gas Unit 1														
341.00	Structures and Improvements	411,070	-13.4%	466,153	406,569	98.90%	229,094	55.73%	378,685	92.12%	341,158	82.99%	37,527	9.13%
342.00	Fuel Holders, Products and Accessories	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
343.00	Prime Movers	678,545	-13.4%	769,470	506,913	74.71%	227,539	33.53%	376,116	55.43%	338,137	49.83%	37,979	5.60%
344.00	Generators and Devices	3,582,271	-13.4%	4,062,295	3,792,993	105.88%	2,427,364	67.76%	4,012,360	112.01%	3,612,659	100.85%	399,701	11.16%
345.00	Accessory Electric Equipment	790,955	-13.4%	896,943	763,625	96.54%	437,003	55.25%	722,354	91.33%	649,584	82.13%	72,770	9.20%
346.00	Miscellaneous Power Plant Equipment	306,369	-13.4%	347,422	313,164	102.22%	177,709	58.00%	293,748	95.88%	264,638	86.38%	29,110	9.50%
Total North Loop Gas Unit 1		**5,769,210**	**-13.4%**	**6,542,284**	**5,783,263**	**100.24%**	**3,498,709**	**60.64%**	**5,783,263**	**100.24%**	**5,206,176**	**90.24%**	**577,087**	**10.00%**
North Loop Gas Unit 2														
341.00	Structures and Improvements	196,078	-17.9%	231,176	215,565	109.94%	142,224	72.53%	207,309	105.73%	180,898	92.26%	26,411	13.47%
342.00	Fuel Holders, Products and Accessories	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
343.00	Prime Movers	263,450	-17.9%	310,608	(327,630)	-124.36%	(91,120)	-34.59%	(132,818)	-50.41%	(158,353)	-60.11%	25,535	9.69%
344.00	Generators and Devices	3,239,719	-17.9%	3,819,629	3,643,451	112.46%	2,399,803	74.07%	3,498,006	107.97%	3,040,622	93.85%	457,384	14.12%
345.00	Accessory Electric Equipment	504,895	-17.9%	595,271	505,786	100.18%	316,796	62.74%	461,769	91.46%	401,129	79.45%	60,640	12.01%
346.00	Miscellaneous Power Plant Equipment	128,559	-17.8%	151,443	148,230	115.30%	103,686	80.65%	151,135	117.56%	131,881	102.58%	19,255	14.98%
Total North Loop Gas Unit 2		**4,332,701**	**-17.9%**	**5,108,126**	**4,185,401**	**96.60%**	**2,871,389**	**66.27%**	**4,185,401**	**96.60%**	**3,596,177**	**83.00%**	**589,225**	**13.60%**

Tucson Electric Power Company
Calculation of Depreciation Reserve Allocation

Account	Description	12/31/14 Investment	Future Net Salvage Percent	Total to be Recovered	Book Reserve Amount	Book Reserve Percent	Theoretical Reserve Amount	Theoretical Reserve Percent	Redistributed Reserve Amount	Redistributed Reserve Percent	Investment Reserve Amount	Investment Reserve Percent	Salvage Reserve Amount	Salvage Reserve Percent
North Loop Gas Unit 3														
341.00	Structures and Improvements	196,078	-16.1%	227,647	212,395	108.32%	140,486	71.65%	216,531	110.43%	191,282	97.55%	25,249	12.88%
342.00	Fuel Holders, Products and Accessories	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
343.00	Prime Movers	948,951	-16.1%	1,101,732	496,044	52.27%	241,432	25.44%	372,118	39.21%	323,696	34.11%	48,422	5.10%
344.00	Generators and Devices	3,030,531	-16.1%	3,518,446	3,333,807	110.01%	2,240,369	73.93%	3,453,065	113.94%	3,031,585	100.03%	421,481	13.91%
345.00	Accessory Electric Equipment	503,907	-16.1%	585,036	493,376	97.91%	312,009	61.92%	480,897	95.43%	423,573	84.06%	57,324	11.38%
346.00	Miscellaneous Power Plant Equipment	128,559	-16.1%	149,257	144,847	112.67%	102,419	79.67%	157,858	122.79%	139,451	108.47%	18,408	14.32%
Total North Loop Gas Unit 3		**4,808,026**	**-16.1%**	**5,582,118**	**4,680,469**	**97.35%**	**3,036,715**	**63.16%**	**4,680,469**	**97.35%**	**4,109,585**	**85.47%**	**570,884**	**11.87%**
North Loop Gas Unit 4														
341.00	Structures and Improvements	85,375	-5.7%	90,241	32,575	38.16%	28,645	33.55%	32,690	38.29%	26,001	30.45%	6,689	7.84%
342.00	Fuel Holders, Products and Accessories	303,037	-5.7%	320,310	104,139	34.37%	91,403	30.16%	104,311	34.42%	101,077	33.35%	3,234	1.07%
343.00	Prime Movers	0	0.0%	0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
344.00	Generators and Devices	14,209,666	-5.7%	15,019,617	4,904,940	34.52%	4,296,382	30.24%	4,903,110	34.51%	4,728,813	33.28%	174,297	1.23%
345.00	Accessory Electric Equipment	1,029,414	-5.7%	1,088,091	328,082	31.87%	289,342	28.11%	330,202	32.08%	314,964	30.60%	15,238	1.48%
346.00	Miscellaneous Power Plant Equipment	92,766	-5.7%	98,054	33,632	36.26%	28,965	31.22%	33,056	35.63%	30,942	33.35%	2,114	2.28%
Total North Loop Gas Unit 4		**15,720,258**	**-5.7%**	**16,616,313**	**5,403,369**	**34.37%**	**4,734,737**	**30.12%**	**5,403,369**	**34.37%**	**5,201,796**	**33.09%**	**201,573**	**1.28%**
Solar Units (Generators and Devices)														
344.00	DeMoss Petrie	1,146,081	-5.0%	1,203,385	334,209	29.16%	509,290	44.44%	610,990	53.31%	581,895	50.77%	29,095	2.54%
344.00	Fort Huachuca	36,709,538	-5.0%	38,545,015	73,938	0.20%	688,304	1.88%	825,751	2.25%	786,429	2.14%	39,321	0.11%
344.00	HQ Rooftop	303,184	-5.0%	318,343	45,437	14.99%	28,424	9.38%	34,099	11.25%	32,476	10.71%	1,624	0.54%
344.00	OH Rooftop	2,594,590	-5.0%	2,724,320	399,653	15.40%	340,540	13.13%	408,542	15.75%	389,088	15.00%	19,454	0.75%
344.00	OH Test Yard	388,459	-5.0%	407,882	233,584	60.13%	162,716	41.89%	195,208	50.25%	185,913	47.86%	9,296	2.39%
344.00	Prairie Fire	19,036,520	-5.0%	19,988,346	1,980,433	10.40%	1,784,674	9.38%	2,141,054	11.25%	2,039,099	10.71%	101,955	0.54%
344.00	Springerville Sites 1-3 (Legacy)	28,766,605	-5.0%	30,204,935	17,515,266	60.89%	12,826,310	44.59%	15,387,588	53.49%	14,654,846	50.94%	732,742	2.55%
344.00	Springerville Site 4	7,873,874	-5.0%	8,267,568	1,606,533	20.40%	1,328,716	16.88%	1,594,047	20.24%	1,518,140	19.28%	75,907	0.96%
343.00	Tucson	87,198	-5.0%	91,558	71,385	81.86%	52,907	60.68%	63,472	72.79%	60,450	69.32%	3,022	3.47%
344.00	U of A Tech Park Site 1	7,723,832	-5.0%	8,110,024	1,576,302	20.41%	1,303,397	16.88%	1,563,671	20.24%	1,489,211	19.28%	74,461	0.96%
345.00	U of A Tech Park Site 2	19,191,952	-5.0%	20,151,550	2,956,201	15.40%	2,518,944	13.13%	3,021,950	15.75%	2,878,048	15.00%	143,902	0.75%
346.00	White Mountain	46,499,099	-5.0%	48,824,054	99,392	0.21%	871,858	1.88%	1,045,959	2.25%	996,151	2.14%	49,808	0.11%
Total Solar Units		**170,320,932**	**-5.0%**	**178,836,979**	**26,892,332**	**15.79%**	**22,416,079**	**13.16%**	**26,892,332**	**15.79%**	**25,611,745**	**15.04%**	**1,280,587**	**0.75%**
Sundt Gas														
341.00	Structures and Improvements	11,090	-2.2%	11,328	11,891	107.22%	6,739	60.77%	11,452	103.26%	11,214	101.12%	238	2.15%
342.00	Fuel Holders, Products and Accessories	788,336	-2.2%	805,285	582,161	73.85%	236,691	30.02%	402,218	51.02%	394,518	50.04%	7,700	0.98%
343.00	Prime Movers	141,618	-2.2%	144,663	139,570	98.55%	62,137	43.88%	105,591	74.56%	103,570	73.13%	2,021	1.43%
344.00	Generators and Devices	8,382,044	-2.1%	8,562,133	8,804,904	105.04%	5,302,004	63.25%	9,007,425	107.46%	8,825,292	105.29%	182,133	2.17%
345.00	Accessory Electric Equipment	1,078,811	-2.2%	1,102,029	1,070,884	99.27%	634,169	58.78%	1,077,878	99.91%	1,056,761	97.96%	21,117	1.96%
346.00	Miscellaneous Power Plant Equipment	49,750	-2.2%	50,825	55,130	110.81%	35,248	70.85%	59,976	120.55%	58,799	118.19%	1,176	2.36%
Total Sundt Gas		**10,451,649**	**-2.1%**	**10,676,263**	**10,664,539**	**102.04%**	**6,276,988**	**60.06%**	**10,664,539**	**102.04%**	**10,450,155**	**99.99%**	**214,384**	**2.05%**
Sundt Gas Unit 1														
341.00	Structures and Improvements	5,545	-2.1%	5,661	5,964	107.55%	3,360	60.60%	5,672	102.29%	5,570	100.45%	102	1.84%
342.00	Fuel Holders, Products and Accessories	394,168	-2.1%	402,446	291,435	73.94%	118,055	29.95%	199,279	50.56%	195,948	49.71%	3,331	0.85%

Tucson Electric Power Company
Calculation of Depreciation Reserve Allocation

Account	Description	12/31/14 Investment	Future Net Salvage Percent	Total to be Recovered	Book Reserve Amount	Book Reserve Percent	Theoretical Reserve Amount	Theoretical Reserve Percent	Redistributed Reserve Amount	Redistributed Reserve Percent	Investment Reserve Amount	Investment Reserve Percent	Salvage Reserve Amount	Salvage Reserve Percent
343.00	Prime Movers	70,809	-2.1%	72,296	70,514	99.58%	30,992	43.77%	52,315	73.88%	51,441	72.65%	874	1.24%
344.00	Generators and Devices	4,315,668	-2.1%	4,406,297	4,541,928	105.24%	2,753,122	63.79%	4,647,294	107.68%	4,566,938	105.82%	80,356	1.86%
345.00	Accessory Electric Equipment	516,231	-2.1%	527,072	514,444	99.65%	306,935	59.46%	518,109	100.36%	509,449	98.69%	8,661	1.68%
346.00	Miscellaneous Power Plant Equipment	19,906	-2.1%	20,324	22,217	111.61%	14,119	70.93%	23,833	119.73%	23,434	117.72%	398	2.00%
Total Sundt Gas Unit 1		**5,322,327**	**-2.1%**	**5,434,096**	**5,446,501**	**102.33%**	**3,226,583**	**60.62%**	**5,446,501**	**102.33%**	**5,352,779**	**100.57%**	**93,723**	**1.76%**
Sundt Gas Unit 2														
341.00	Structures and Improvements	5,545	-2.2%	5,667	5,927	106.89%	3,379	60.94%	5,780	104.24%	5,644	101.79%	136	2.45%
342.00	Fuel Holders, Products and Accessories	394,168	-2.2%	402,840	290,725	73.76%	118,636	30.10%	202,939	51.49%	198,571	50.38%	4,369	1.11%
343.00	Prime Movers	70,809	-2.2%	72,367	69,056	97.52%	31,145	43.98%	53,276	75.24%	52,129	73.62%	1,147	1.62%
344.00	Generators and Devices	4,066,376	-2.2%	4,155,836	4,262,976	104.83%	2,548,882	62.68%	4,360,131	107.22%	4,258,355	104.72%	101,777	2.50%
345.00	Accessory Electric Equipment	562,580	-2.2%	574,957	556,440	98.91%	327,234	58.17%	559,768	99.50%	547,312	97.29%	12,456	2.21%
346.00	Miscellaneous Power Plant Equipment	29,844	-2.2%	30,501	32,913	110.28%	21,129	70.80%	36,143	121.11%	35,365	118.50%	778	2.61%
Total Sundt Gas Unit 2		**5,129,322**	**-2.2%**	**5,242,167**	**5,218,038**	**101.73%**	**3,050,404**	**59.47%**	**5,218,038**	**101.73%**	**5,097,376**	**99.38%**	**120,662**	**2.35%**

Tucson Electric Power Company
Calculation of Average Net Salvage

Account	Description	12/31/14 Investment	Derived Additions	Calculated Retirements	Salvage Rate Historical	Salvage Rate Future	Calculated Net Salvage Historical	Calculated Net Salvage Future	Calculated Net Salvage Total	Average Rate
STEAM PRODUCTION										
310.00	Rights-of-Way	5,106,662	6,273,568	1,166,906	0.0%	0.0%	0	(575)	(575)	0.0%
311.00	Structures and Improvements	205,277,689	241,715,429	36,437,740	-0.7%	-13.9%	(254,013)	(28,588,527)	(28,842,540)	-11.9%
312.00	Boiler Plant Equipment	1,091,953,161	1,269,797,647	177,844,486	-5.3%	-11.2%	(9,352,892)	(121,887,933)	(131,240,825)	-10.3%
314.00	Turbogenerator Units	303,041,923	364,977,004	61,935,081	-3.6%	-10.8%	(2,209,759)	(32,578,923)	(34,788,682)	-9.5%
315.00	Accessory Electric Equipment	144,581,471	151,813,441	7,231,970	-0.8%	-13.4%	(54,707)	(19,323,746)	(19,378,453)	-12.8%
316.00	Miscellaneous Power Plant Equipment	25,222,863	27,947,025	2,724,162	-0.1%	-8.4%	(1,619)	(2,110,273)	(2,111,892)	-7.6%
Total Steam Production Plant		**1,775,183,769**	**2,062,524,114**	**287,340,345**	**-4.1%**	**-11.5%**	**(11,872,989)**	**(204,489,977)**	**(216,362,966)**	**-10.5%**
OTHER PRODUCTION										
Non-Solar										
341.00	Structures and Improvements	23,403,461	23,624,549	221,088	3.3%	-7.7%	7,192	(1,794,792)	(1,787,600)	-7.6%
342.00	Fuel Holders, Products and Accessories	19,977,187	19,985,288	8,101	0.0%	-7.3%	0	(1,458,405)	(1,458,405)	-7.3%
343.00	Prime Movers	202,005,134	205,281,935	3,276,801	0.0%	-4.9%	0	(9,809,321)	(9,809,321)	-4.8%
344.00	Generators and Devices	105,487,225	115,467,853	9,980,628	-0.4%	-5.5%	(43,629)	(5,840,008)	(5,883,637)	-5.1%
345.00	Accessory Electric Equipment	13,809,819	15,595,403	1,785,584	0.0%	-5.3%	(318)	(733,078)	(733,396)	-4.7%
346.00	Miscellaneous Power Plant Equipment	15,307,160	15,414,670	107,510	0.0%	-7.3%	0	(1,111,369)	(1,111,369)	-7.2%
Total Non-Solar		**379,989,986**	**395,369,698**	**15,379,712**	**-0.2%**	**-5.5%**	**(36,755)**	**(20,746,973)**	**(20,783,728)**	**-5.3%**
Solar										
344.00	Generators and Devices	170,320,932	170,320,932	0	0.0%	-5.0%	0	(8,516,047)	(8,516,047)	-5.0%
Total Solar		**170,320,932**	**170,320,932**	**0**	**0.0%**	**-5.0%**	**0**	**(8,516,047)**	**(8,516,047)**	**-5.0%**
Total Other Production Plant		**550,310,918**	**565,690,630**	**15,379,712**	**-0.2%**	**-5.3%**	**(36,755)**	**(29,263,020)**	**(29,299,775)**	**-5.2%**
DISTRIBUTION PLANT										
360.RW	Rights-of-Way	7,865,073	7,882,488	17,415	0.0%	0.0%	0	0	0	0.0%
361.00	Structures and Improvements	11,402,474	12,185,407	782,933	0.0%	0.0%	0	0	0	0.0%
362.00	Station Equipment	157,067,530	170,550,706	13,483,176	0.0%	0.0%	0	0	0	0.0%
364.00	Poles, Towers and Fixtures	222,006,967	233,941,047	11,934,080	0.0%	0.0%	0	0	0	0.0%
365.00	Overhead Conductors and Devices	175,675,966	185,805,025	10,129,059	0.0%	0.0%	0	0	0	0.0%
366.00	Underground Conduit	58,725,355	60,132,553	1,407,198	0.0%	0.0%	0	0	0	0.0%

Tucson Electric Power Company
Calculation of Average Net Salvage

Account	Description	12/31/14 Investment	Derived Additions	Calculated Retirements	Salvage Rate Historical	Salvage Rate Future	Calculated Net Salvage Historical	Calculated Net Salvage Future	Calculated Net Salvage Total	Average Rate
367.00	Underground Conductors and Devices	297,183,135	304,814,478	7,631,343	0.0%	0.0%	0	0	0	0.0%
368.OH	Line Transformers - Overhead	103,657,922	122,002,086	18,344,164	0.0%	0.0%	0	0	0	0.0%
368.UG	Line Transformers - Underground	172,890,932	183,763,798	10,872,866	0.0%	0.0%	0	0	0	0.0%
369.OH	Services - Overhead	17,542,236	20,027,424	2,485,188	0.0%	0.0%	0	0	0	0.0%
369.UG	Services - Underground	112,947,714	113,190,446	242,732	0.0%	0.0%	0	0	0	0.0%
370.00	Meters	44,869,823	83,815,254	38,945,431	0.0%	0.0%	0	0	0	0.0%
373.00	Street Lighting and Signal Systems	11,778,362	12,730,933	952,571	0.0%	0.0%	0	0	0	0.0%
Total Distribution Plant		**1,393,613,489**	**1,510,841,645**	**117,228,156**	**0.0%**	**0.0%**	**0**	**0**	**0**	**0.0%**
GENERAL PLANT										
Depreciable										
390.00	Structures and Improvements	135,680,348	142,216,884	6,536,536	-25.1%	-5.0%	(1,640,671)	(6,784,017)	(8,424,688)	-5.9%
392.C0	Transportation - Class 0	1,238,946	2,693,017	1,454,071	18.8%	15.0%	273,365	185,842	459,207	17.1%
392.C1	Transportation - Class 1	7,718,183	18,234,904	10,516,721	18.8%	15.0%	1,977,144	1,157,727	3,134,871	17.2%
392.C2	Transportation - Class 2	3,839,907	11,814,454	7,974,547	18.8%	15.0%	1,499,215	575,986	2,075,201	17.6%
392.C3	Transportation - Class 3	2,076,936	9,677,240	7,600,304	18.8%	15.0%	1,428,857	311,540	1,740,398	18.0%
392.C4	Transportation - Class 4	2,935,027	14,756,225	11,821,198	18.8%	15.0%	2,222,385	440,254	2,662,639	18.0%
392.C5	Transportation - Class 5	7,982,715	15,016,948	7,034,233	18.8%	15.0%	1,322,436	1,197,407	2,519,843	16.8%
392.C6	Transportation - Class 6	365,200	365,200	0	18.8%	15.0%	0	54,780	54,780	15.0%
392.C7	Transportation - Class 7	1,047,216	1,047,216	0	18.8%	15.0%	0	157,082	157,082	15.0%
392.C8	Transportation - Class 8	9,957,500	10,369,813	412,313	18.8%	15.0%	77,515	1,493,625	1,571,140	15.2%
392.C9	Transportation - Class 9	4,252,286	4,607,987	355,701	18.8%	15.0%	66,872	637,843	704,715	15.3%
396.00	Power Operatied Equipment	11,860,940	20,256,159	8,395,219	2.3%	0.0%	193,090	0	193,090	1.0%
397.EM	EMS and SCADA Equipment	11,304,371	11,481,719	177,348	0.0%	0.0%	0	0	0	0.0%
Total Depreciable		**200,259,575**	**262,537,766**	**62,278,191**	**11.9%**	**-0.3%**	**7,420,208**	**(571,930)**	**6,848,278**	**2.6%**
Amortizable										
391.00	Furniture and Office Equipment	23,964,411	29,004,709	5,040,298	0.0%	0.0%	0	0	0	0.0%
391.20	Network and Data Equipment	29,359,636	87,362,414	58,002,778	0.0%	0.0%	0	0	0	0.0%
393.00	Stores Equipment	1,852,479	4,720,343	2,867,864	0.0%	0.0%	0	0	0	0.0%
394.00	Tools, Shop and Garage Equipment	6,934,368	13,766,165	6,831,797	0.0%	0.0%	0	0	0	0.0%
395.00	Laboratory Equipment	5,091,270	8,948,263	3,856,993	0.0%	0.0%	0	0	0	0.0%

Tucson Electric Power Company
Calculation of Average Net Salvage

Account	Description	12/31/14 Investment	Derived Additions	Calculated Retirements	Salvage Rate Historical	Salvage Rate Future	Calculated Net Salvage Historical	Calculated Net Salvage Future	Calculated Net Salvage Total	Average Rate
397.20	Telecommunications Equipment	57,456,141	84,671,141	27,215,000	0.0%	0.0%	0	0	0	0.0%
398.00	Miscellaneous Equipment	4,348,209	6,295,272	1,947,063	0.0%	0.0%	0	0	0	0.0%
Total Amortizable		**129,006,514**	**234,768,307**	**105,761,793**	**0.0%**	**0.0%**	**0**	**0**	**0**	**0.0%**
Total General Plant		**329,266,089**	**497,306,073**	**168,039,984**	**4.4%**	**-0.2%**	**7,420,208**	**(571,930)**	**6,848,278**	**1.4%**
SUBTOTAL		**4,048,374,265**	**4,636,362,462**	**587,988,197**	**-0.8%**	**-5.8%**	**(4,489,536)**	**(234,324,927)**	**(238,814,463)**	**-5.2%**
NET SALVAGE										
108.02	Distribution	1,393,613,489	1,511,081,011	117,467,522	-2.9%	-5.0%	(3,406,558)	(69,680,674)	(73,087,233)	-4.8%
Total Net Salvage		**1,393,613,489**	**1,511,081,011**	**117,467,522**	**-2.9%**	**-5.0%**	**(3,406,558)**	**(69,680,674)**	**(73,087,233)**	**-4.8%**
TOTAL UTILITY		**4,048,374,265**	**6,147,443,473**	**705,455,719**	**-1.1%**	**-7.5%**	**(7,896,094)**	**(304,005,601)**	**(311,901,695)**	**-5.1%**
STEAM PRODUCTION (by Unit)										
Four Corners										
310.00	Rights-of-Way	0	0	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	2,982,777	3,073,950	91,173	0.0%	-4.8%	0	(144,500)	(144,500)	-4.7%
312.00	Boiler Plant Equipment	76,402,061	83,264,815	6,862,754	-12.4%	-4.8%	(851,462)	(3,698,457)	(4,549,919)	-5.5%
314.00	Turbogenerator Units	12,359,480	13,995,637	1,636,157	0.0%	-4.8%	0	(594,437)	(594,437)	-4.2%
315.00	Accessory Electric Equipment	4,390,980	5,176,981	786,001	0.0%	-4.8%	0	(212,566)	(212,566)	-4.1%
316.00	Miscellaneous Power Plant Equipment	3,832,234	4,006,877	174,643	0.0%	-4.6%	0	(178,134)	(178,134)	-4.4%
Total Four Corners		**99,967,532**	**109,518,260**	**9,550,728**	**-8.9%**	**-4.8%**	**(851,462)**	**(4,828,093)**	**(5,679,555)**	**-5.2%**
Four Corners Unit 4										
310.00	Rights-of-Way	0	0	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	1,524,414	1,568,186	43,772	0.0%	-4.6%	0	(70,123)	(70,123)	-4.5%
312.00	Boiler Plant Equipment	39,609,538	43,976,009	4,366,471	-19.5%	-4.6%	(851,462)	(1,822,039)	(2,673,501)	-6.1%
314.00	Turbogenerator Units	7,179,362	8,391,807	1,212,445	0.0%	-4.6%	0	(330,251)	(330,251)	-3.9%
315.00	Accessory Electric Equipment	2,274,836	2,867,113	592,277	0.0%	-4.6%	0	(104,642)	(104,642)	-3.6%
316.00	Miscellaneous Power Plant Equipment	1,929,161	2,037,484	108,323	0.0%	-4.4%	0	(84,883)	(84,883)	-4.2%
Total Four Corners Unit 4		**52,517,311**	**58,840,599**	**6,323,288**	**-13.5%**	**-4.6%**	**(851,462)**	**(2,411,938)**	**(3,263,400)**	**-5.5%**

Tucson Electric Power Company
Calculation of Average Net Salvage

Account	Description	12/31/14 Investment	Derived Additions	Calculated Retirements	Salvage Rate Historical	Salvage Rate Future	Calculated Net Salvage Historical	Calculated Net Salvage Future	Calculated Net Salvage Total	Average Rate
Four Corners Unit 5										
310.00	Rights-of-Way	0	0	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	1,458,363	1,505,764	47,401	0.0%	-5.1%	0	(74,377)	(74,377)	-4.9%
312.00	Boiler Plant Equipment	36,792,523	39,288,806	2,496,283	0.0%	-5.1%	0	(1,876,419)	(1,876,419)	-4.8%
314.00	Turbogenerator Units	5,180,118	5,603,830	423,712	0.0%	-5.1%	0	(264,186)	(264,186)	-4.7%
315.00	Accessory Electric Equipment	2,116,144	2,309,868	193,724	0.0%	-5.1%	0	(107,923)	(107,923)	-4.7%
316.00	Miscellaneous Power Plant Equipment	1,903,073	1,969,393	66,320	0.0%	-4.9%	0	(93,251)	(93,251)	-4.7%
Total Four Corners Unit 5		**47,450,221**	**50,677,661**	**3,227,440**	**0.0%**	**-5.1%**	**0**	**(2,416,155)**	**(2,416,155)**	**-4.8%**
Navajo										
310.00	Rights-of-Way	12,229	12,229	0	0.0%	-4.7%	0	(575)	(575)	-4.7%
311.00	Structures and Improvements	18,655,156	19,133,681	478,525	-0.6%	-4.9%	(2,794)	(908,957)	(911,751)	-4.8%
312.00	Boiler Plant Equipment	88,544,201	93,542,762	4,998,561	1.6%	-4.9%	78,293	(4,336,677)	(4,258,384)	-4.6%
314.00	Turbogenerator Units	20,255,526	21,695,188	1,439,662	-0.5%	-4.9%	(7,076)	(994,080)	(1,001,156)	-4.6%
315.00	Accessory Electric Equipment	14,829,858	14,944,456	114,598	2.9%	-4.9%	3,374	(722,356)	(718,982)	-4.8%
316.00	Miscellaneous Power Plant Equipment	4,518,597	4,527,877	9,280	-17.4%	-4.7%	(1,619)	(212,307)	(213,926)	-4.7%
Total Navajo		**146,815,567**	**153,856,193**	**7,040,626**	**1.0%**	**-4.9%**	**70,179**	**(7,174,952)**	**(7,104,773)**	**-4.6%**
Navajo Unit 1										
310.00	Rights-of-Way	0	0	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	3,190,563	3,183,276	(7,287)	0.0%	-4.8%	0	(153,147)	(153,147)	-4.8%
312.00	Boiler Plant Equipment	27,198,582	28,591,944	1,393,362	-4.9%	-4.8%	(68,275)	(1,305,532)	(1,373,807)	-4.8%
314.00	Turbogenerator Units	6,860,989	7,568,560	707,571	-1.0%	-4.8%	(7,076)	(329,327)	(336,403)	-4.4%
315.00	Accessory Electric Equipment	3,544,300	3,763,595	219,295	-0.6%	-4.8%	(1,316)	(170,126)	(171,442)	-4.6%
316.00	Miscellaneous Power Plant Equipment	471,227	492,993	21,766	-4.0%	-4.7%	(871)	(22,148)	(23,018)	-4.7%
Total Navajo Unit 1		**41,265,661**	**43,600,368**	**2,334,707**	**-3.3%**	**-4.8%**	**(77,537)**	**(1,980,281)**	**(2,057,817)**	**-4.7%**
Navajo Unit 2										
310.00	Rights-of-Way	0	0	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	1,802,685	1,882,084	79,399	0.0%	-5.2%	0	(93,740)	(93,740)	-5.0%
312.00	Boiler Plant Equipment	26,882,286	28,261,337	1,379,051	4.9%	-5.2%	67,573	(1,397,879)	(1,330,305)	-4.7%

Tucson Electric Power Company
Calculation of Average Net Salvage

Account	Description	12/31/14 Investment	Derived Additions	Calculated Retirements	Salvage Rate Historical	Salvage Rate Future	Calculated Net Salvage Historical	Calculated Net Salvage Future	Calculated Net Salvage Total	Average Rate
314.00	Turbogenerator Units	6,926,050	7,024,429	98,379	0.0%	-5.2%	0	(360,155)	(360,155)	-5.1%
315.00	Accessory Electric Equipment	3,172,330	3,352,457	180,127	-0.6%	-5.2%	(1,081)	(164,961)	(166,042)	-5.0%
316.00	Miscellaneous Power Plant Equipment	515,874	539,942	24,068	-3.6%	-4.9%	(866)	(25,278)	(26,144)	-4.8%
Total Navajo Unit 2		**39,299,225**	**41,060,249**	**1,761,024**	**3.7%**	**-5.2%**	**65,626**	**(2,042,012)**	**(1,976,386)**	**-4.8%**
Navajo Unit 3										
310.00	Rights-of-Way	0	0	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	3,681,511	3,738,690	57,179	0.0%	-4.7%	0	(173,031)	(173,031)	-4.6%
312.00	Boiler Plant Equipment	27,718,514	29,815,550	2,097,036	5.3%	-4.7%	111,143	(1,302,770)	(1,191,627)	-4.0%
314.00	Turbogenerator Units	6,178,944	6,805,747	626,803	0.0%	-4.7%	0	(290,410)	(290,410)	-4.3%
315.00	Accessory Electric Equipment	5,139,872	4,794,821	(345,051)	0.3%	-4.7%	(1,035)	(241,574)	(242,609)	-5.1%
316.00	Miscellaneous Power Plant Equipment	549,362	455,762	(93,600)	0.3%	-4.5%	(281)	(24,721)	(25,002)	-5.5%
Total Navajo Unit 3		**43,268,203**	**45,610,570**	**2,342,367**	**4.7%**	**-4.7%**	**109,827**	**(2,032,507)**	**(1,922,680)**	**-4.2%**
Navajo Common										
310.00	Rights-of-Way	12,229	12,229	0	0.0%	-4.7%	0	(575)	(575)	-4.7%
311.00	Structures and Improvements	9,980,397	10,329,631	349,234	-0.8%	-4.9%	(2,794)	(489,039)	(491,833)	-4.8%
312.00	Boiler Plant Equipment	6,744,819	6,873,931	129,112	-24.9%	-4.9%	(32,149)	(330,496)	(362,645)	-5.3%
314.00	Turbogenerator Units	289,543	296,452	6,909	0.0%	-4.9%	0	(14,188)	(14,188)	-4.8%
315.00	Accessory Electric Equipment	2,973,356	3,033,583	60,227	11.3%	-4.9%	6,806	(145,694)	(138,889)	-4.6%
316.00	Miscellaneous Power Plant Equipment	2,982,134	3,039,180	57,046	0.7%	-4.7%	399	(140,160)	(139,761)	-4.6%
Total Navajo Common		**22,982,478**	**23,585,006**	**602,528**	**-4.6%**	**-4.9%**	**(27,738)**	**(1,120,153)**	**(1,147,890)**	**-4.9%**
San Juan										
310.00	Rights-of-Way	0	0	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	14,437,744	15,360,481	922,737	0.0%	-7.9%	0	(1,141,811)	(1,141,811)	-7.4%
312.00	Boiler Plant Equipment	154,506,908	179,068,616	24,561,708	-10.9%	-9.7%	(2,682,943)	(14,961,956)	(17,644,899)	-9.9%
314.00	Turbogenerator Units	44,295,673	47,886,955	3,591,282	0.0%	-8.0%	0	(3,543,654)	(3,543,654)	-7.4%
315.00	Accessory Electric Equipment	10,063,526	10,694,978	631,452	0.0%	-8.0%	0	(805,082)	(805,082)	-7.5%
316.00	Miscellaneous Power Plant Equipment	2,009,555	2,285,721	276,166	0.0%	-7.6%	0	(152,893)	(152,893)	-6.7%
Total San Juan		**225,313,406**	**255,296,751**	**29,983,345**	**-8.9%**	**-9.1%**	**(2,682,943)**	**(20,605,396)**	**(23,288,339)**	**-9.1%**

Tucson Electric Power Company
Calculation of Average Net Salvage

Account	Description	12/31/14 Investment	Derived Additions	Calculated Retirements	Salvage Rate Historical	Salvage Rate Future	Calculated Net Salvage Historical	Calculated Net Salvage Future	Calculated Net Salvage Total	Average Rate
San Juan Unit 1										
310.00	Rights-of-Way	0	0	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	14,268,404	15,191,141	922,737	0.0%	-8.0%	0	(1,141,472)	(1,141,472)	-7.5%
312.00	Boiler Plant Equipment	146,453,029	170,696,078	24,243,049	-12.1%	-8.0%	(2,933,409)	(11,716,242)	(14,649,651)	-8.6%
314.00	Turbogenerator Units	44,295,673	47,886,955	3,591,282	0.0%	-8.0%	0	(3,543,654)	(3,543,654)	-7.4%
315.00	Accessory Electric Equipment	10,063,526	10,694,978	631,452	0.0%	-8.0%	0	(805,082)	(805,082)	-7.5%
316.00	Miscellaneous Power Plant Equipment	1,960,172	2,236,338	276,166	0.0%	-7.8%	0	(152,893)	(152,893)	-6.8%
Total San Juan Unit 1		**217,040,804**	**246,705,490**	**29,664,686**	**-9.9%**	**-8.0%**	**(2,933,409)**	**(17,359,344)**	**(20,292,753)**	**-8.2%**
San Juan Common										
310.00	Rights-of-Way	0	0	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	169,340	169,340	0	0.0%	-0.2%	0	(339)	(339)	-0.2%
312.00	Boiler Plant Equipment	8,053,879	8,372,538	318,659	78.6%	-40.3%	250,466	(3,245,713)	(2,995,247)	-35.8%
314.00	Turbogenerator Units	0	0	0	0.0%	0.0%	0	0	0	0.0%
315.00	Accessory Electric Equipment	0	0	0	0.0%	0.0%	0	0	0	0.0%
316.00	Miscellaneous Power Plant Equipment	49,383	49,383	0	0.0%	0.0%	0	0	0	0.0%
Total San Juan Common		**8,272,602**	**8,591,261**	**318,659**	**78.6%**	**-39.2%**	**250,466**	**(3,246,052)**	**(2,995,586)**	**-34.9%**
Springerville										
310.00	Rights-of-Way	5,094,433	6,261,339	1,166,906	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	141,726,641	175,350,915	33,624,274	-0.7%	-12.9%	(251,219)	(18,346,682)	(18,597,901)	-10.6%
312.00	Boiler Plant Equipment	641,687,365	772,876,714	131,189,349	-4.5%	-10.0%	(5,896,780)	(63,899,236)	(69,796,016)	-9.0%
314.00	Turbogenerator Units	173,649,915	223,365,420	49,715,505	-4.4%	-3.8%	(2,202,683)	(6,543,559)	(8,746,242)	-3.9%
315.00	Accessory Electric Equipment	75,864,618	78,903,325	3,038,707	-1.9%	-5.4%	(58,081)	(4,128,370)	(4,186,451)	-5.3%
316.00	Miscellaneous Power Plant Equipment	12,528,984	14,477,485	1,948,501	0.0%	-5.8%	0	(726,122)	(726,122)	-5.0%
Total Springerville		**1,050,551,956**	**1,271,235,198**	**220,683,242**	**-3.8%**	**-8.9%**	**(8,408,763)**	**(93,643,968)**	**(102,052,731)**	**-8.0%**
Springerville Unit 1										
310.00	Rights-of-Way	0	0	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	20,076,015	26,483,850	6,407,835	0.0%	-3.3%	0	(662,508)	(662,508)	-2.5%
312.00	Boiler Plant Equipment	185,682,490	243,028,846	57,346,356	0.0%	-3.3%	0	(6,127,522)	(6,127,522)	-2.5%
314.00	Turbogenerator Units	49,547,312	65,088,339	15,541,027	0.0%	-3.3%	0	(1,635,061)	(1,635,061)	-2.5%

Tucson Electric Power Company
Calculation of Average Net Salvage

Account	Description	12/31/14 Investment	Derived Additions	Calculated Retirements	Salvage Rate Historical	Salvage Rate Future	Calculated Net Salvage Historical	Calculated Net Salvage Future	Calculated Net Salvage Total	Average Rate
315.00	Accessory Electric Equipment	21,214,167	22,841,460	1,627,293	0.0%	-3.3%	0	(700,068)	(700,068)	-3.1%
316.00	Miscellaneous Power Plant Equipment	3,277,742	4,778,042	1,500,300	0.0%	-2.9%	0	(95,055)	(95,055)	-2.0%
Total Springerville Unit 1		**279,797,726**	**362,220,537**	**82,422,811**	**0.0%**	**-3.3%**	**0**	**(9,220,214)**	**(9,220,214)**	**-2.5%**
Springerville Unit 1 Common										
310.00	Rights-of-Way	1,143,496	2,310,402	1,166,906	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	52,492,826	74,990,847	22,498,021	0.0%	-9.8%	0	(5,144,297)	(5,144,297)	-6.9%
312.00	Boiler Plant Equipment	14,854,799	19,321,712	4,466,913	0.0%	-9.8%	0	(1,455,770)	(1,455,770)	-7.5%
314.00	Turbogenerator Units	1,264,322	1,551,370	287,048	0.0%	-9.8%	0	(123,904)	(123,904)	-8.0%
315.00	Accessory Electric Equipment	9,627,097	9,774,817	147,720	0.0%	-9.8%	0	(943,456)	(943,456)	-9.7%
316.00	Miscellaneous Power Plant Equipment	1,959,012	2,140,360	181,348	0.0%	-9.4%	0	(184,147)	(184,147)	-8.6%
Total Springerville Unit 1 Common		**81,341,552**	**110,089,508**	**28,747,956**	**0.0%**	**-9.7%**	**0**	**(7,851,573)**	**(7,851,573)**	**-7.1%**
Springerville Unit 2										
310.00	Rights-of-Way	0	0	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	36,540,030	38,669,006	2,128,976	-11.8%	-3.7%	(251,219)	(1,351,981)	(1,603,200)	-4.1%
312.00	Boiler Plant Equipment	295,922,545	358,654,246	62,731,701	-9.4%	-3.7%	(5,896,780)	(10,949,134)	(16,845,914)	-4.7%
314.00	Turbogenerator Units	122,055,348	155,942,778	33,887,430	-6.5%	-3.7%	(2,202,683)	(4,516,048)	(6,718,731)	-4.3%
315.00	Accessory Electric Equipment	42,346,939	43,609,568	1,262,629	-4.6%	-3.7%	(58,081)	(1,566,837)	(1,624,918)	-3.7%
316.00	Miscellaneous Power Plant Equipment	6,624,669	6,879,594	254,925	0.0%	-3.3%	0	(218,614)	(218,614)	-3.2%
Total Springerville Unit 2		**503,489,531**	**603,755,192**	**100,265,661**	**-8.4%**	**-3.7%**	**(8,408,763)**	**(18,602,614)**	**(27,011,377)**	**-4.5%**
Springerville Unit 2 Common (Leasehold Imp.)										
310.00	Rights-of-Way	2,280,838	2,280,838	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	32,617,770	35,207,212	2,589,442	0.0%	-34.3%	0	(11,187,895)	(11,187,895)	-31.8%
312.00	Boiler Plant Equipment	6,282,729	7,670,230	1,387,501	0.0%	-34.3%	0	(2,154,976)	(2,154,976)	-28.1%
314.00	Turbogenerator Units	782,933	782,933	0	0.0%	-34.3%	0	(268,546)	(268,546)	-34.3%
315.00	Accessory Electric Equipment	2,676,415	2,677,480	1,065	0.0%	-34.3%	0	(918,010)	(918,010)	-34.3%
316.00	Miscellaneous Power Plant Equipment	667,561	679,489	11,928	0.0%	-34.2%	0	(228,306)	(228,306)	-33.6%
Total Springerville Unit 2 Common		**45,308,246**	**49,298,182**	**3,989,936**	**0.0%**	**-32.6%**	**0**	**(14,757,733)**	**(14,757,733)**	**-29.9%**
Springerville Coal Handling										

Tucson Electric Power Company
Calculation of Average Net Salvage

Account	Description	12/31/14 Investment	Derived Additions	Calculated Retirements	Salvage Rate Historical	Salvage Rate Future	Calculated Net Salvage Historical	Calculated Net Salvage Future	Calculated Net Salvage Total	Average Rate
310.00	Rights-of-Way	1,670,099	1,670,099	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	0	0	0	0.0%	0.0%	0	0	0	0.0%
312.00	Boiler Plant Equipment	138,944,802	144,201,680	5,256,878	0.0%	-31.1%	0	(43,211,833)	(43,211,833)	-30.0%
314.00	Turbogenerator Units	0	0	0	0.0%	0.0%	0	0	0	0.0%
315.00	Accessory Electric Equipment	0	0	0	0.0%	0.0%	0	0	0	0.0%
316.00	Miscellaneous Power Plant Equipment	0	0	0	0.0%	0.0%	0	0	0	0.0%
Total Springerville Coal Handling		**140,614,901**	**145,871,779**	**5,256,878**	**0.0%**	**-30.7%**	**0**	**(43,211,833)**	**(43,211,833)**	**-29.6%**
Sundt										
310.00	Rights-of-Way	0	0	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	27,475,371	28,796,402	1,321,031	0.0%	-29.3%	0	(8,046,578)	(8,046,578)	-27.9%
312.00	Boiler Plant Equipment	130,812,626	141,044,740	10,232,114	0.0%	-26.7%	0	(34,991,607)	(34,991,607)	-24.8%
314.00	Turbogenerator Units	52,481,329	58,033,804	5,552,475	0.0%	-39.8%	0	(20,903,194)	(20,903,194)	-36.0%
315.00	Accessory Electric Equipment	39,432,489	42,093,701	2,661,212	0.0%	-34.1%	0	(13,455,372)	(13,455,372)	-32.0%
316.00	Miscellaneous Power Plant Equipment	2,333,493	2,649,065	315,572	0.0%	-36.0%	0	(840,817)	(840,817)	-31.7%
Total Sundt		**252,535,308**	**272,617,712**	**20,082,404**	**0.0%**	**-31.0%**	**0**	**(78,237,567)**	**(78,237,567)**	**-28.7%**
Sundt Unit 1										
310.00	Rights-of-Way	0	0	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	3,926,062	4,268,893	342,831	0.0%	-47.1%	0	(1,849,175)	(1,849,175)	-43.3%
312.00	Boiler Plant Equipment	13,782,181	16,399,259	2,617,078	0.0%	-47.2%	0	(6,505,189)	(6,505,189)	-39.7%
314.00	Turbogenerator Units	10,237,507	11,467,321	1,229,814	0.0%	-47.2%	0	(4,832,103)	(4,832,103)	-42.1%
315.00	Accessory Electric Equipment	6,536,315	7,107,197	570,882	0.0%	-47.7%	0	(3,117,822)	(3,117,822)	-43.9%
316.00	Miscellaneous Power Plant Equipment	490,578	516,709	26,131	0.0%	-47.5%	0	(233,025)	(233,025)	-45.1%
Total Sundt Unit 1		**34,972,643**	**39,759,379**	**4,786,736**	**0.0%**	**-47.3%**	**0**	**(16,537,315)**	**(16,537,315)**	**-41.6%**
Sundt Unit 2										
310.00	Rights-of-Way	0	0	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	2,812,689	3,151,250	338,561	0.0%	-51.3%	0	(1,442,909)	(1,442,909)	-45.8%
312.00	Boiler Plant Equipment	14,371,609	15,058,926	687,317	0.0%	-51.2%	0	(7,358,264)	(7,358,264)	-48.9%
314.00	Turbogenerator Units	8,451,923	9,232,349	780,426	0.0%	-51.2%	0	(4,327,385)	(4,327,385)	-46.9%
315.00	Accessory Electric Equipment	6,205,700	6,531,575	325,875	0.0%	-51.6%	0	(3,202,141)	(3,202,141)	-49.0%

Tucson Electric Power Company
Calculation of Average Net Salvage

Account	Description	12/31/14 Investment	Derived Additions	Calculated Retirements	Salvage Rate Historical	Salvage Rate Future	Calculated Net Salvage Historical	Calculated Net Salvage Future	Calculated Net Salvage Total	Average Rate
316.00	Miscellaneous Power Plant Equipment	383,824	411,098	27,274	0.0%	-51.4%	0	(197,286)	(197,286)	-48.0%
Total Sundt Unit 2		**32,225,745**	**34,385,198**	**2,159,453**	**0.0%**	**-51.3%**	**0**	**(16,527,985)**	**(16,527,985)**	**-48.1%**
Sundt Unit 3										
310.00	Rights-of-Way	0	0	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	2,762,012	3,083,662	321,650	0.0%	-56.3%	0	(1,555,013)	(1,555,013)	-50.4%
312.00	Boiler Plant Equipment	11,980,831	12,808,330	827,499	0.0%	-56.3%	0	(6,745,208)	(6,745,208)	-52.7%
314.00	Turbogenerator Units	14,830,615	16,380,197	1,549,582	0.0%	-56.3%	0	(8,349,636)	(8,349,636)	-51.0%
315.00	Accessory Electric Equipment	6,140,139	6,922,100	781,961	0.0%	-56.3%	0	(3,456,898)	(3,456,898)	-49.9%
316.00	Miscellaneous Power Plant Equipment	404,717	458,756	54,039	0.0%	-56.1%	0	(227,046)	(227,046)	-49.5%
Total Sundt Unit 3		**36,118,314**	**39,653,045**	**3,534,731**	**0.0%**	**-56.3%**	**0**	**(20,333,801)**	**(20,333,801)**	**-51.3%**
Sundt Unit 4										
310.00	Rights-of-Way	0	0	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	17,974,608	18,292,597	317,989	0.0%	-17.8%	0	(3,199,480)	(3,199,480)	-17.5%
312.00	Boiler Plant Equipment	80,576,055	86,676,275	6,100,220	0.0%	-17.8%	0	(14,342,538)	(14,342,538)	-16.5%
314.00	Turbogenerator Units	18,961,284	20,953,937	1,992,653	0.0%	-17.9%	0	(3,394,070)	(3,394,070)	-16.2%
315.00	Accessory Electric Equipment	20,550,335	21,532,829	982,494	0.0%	-17.9%	0	(3,678,510)	(3,678,510)	-17.1%
316.00	Miscellaneous Power Plant Equipment	1,054,374	1,262,502	208,128	0.0%	-17.4%	0	(183,461)	(183,461)	-14.5%
Total Sundt Unit 4		**139,116,656**	**148,718,140**	**9,601,484**	**0.0%**	**-17.8%**	**0**	**(24,798,059)**	**(24,798,059)**	**-16.7%**
Sundt Solar Booster (Areva)										
310.00	Rights-of-Way	0	0	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	0	0	0	0.0%	0.0%	0	0	0	0.0%
312.00	Boiler Plant Equipment	10,101,950	10,101,950	0	0.0%	-0.4%	0	(40,408)	(40,408)	-0.4%
314.00	Turbogenerator Units	0	0	0	0.0%	0.0%	0	0	0	0.0%
315.00	Accessory Electric Equipment	0	0	0	0.0%	0.0%	0	0	0	0.0%
316.00	Miscellaneous Power Plant Equipment	0	0	0	0.0%	0.0%	0	0	0	0.0%
Total Sundt Solar Booster (Areva)		**10,101,950**	**10,101,950**	**0**	**#DIV/0!**	**-0.4%**	**0**	**(40,408)**	**(40,408)**	**-0.4%**

OTHER PRODUCTION (by Unit)

Tucson Electric Power Company
Calculation of Average Net Salvage

Account	Description	12/31/14 Investment	Derived Additions	Calculated Retirements	Salvage Rate Historical	Salvage Rate Future	Calculated Net Salvage Historical	Calculated Net Salvage Future	Calculated Net Salvage Total	Average Rate
DeMoss Petrie Gas Unit 1										
341.00	Structures and Improvements	761,988	941,331	179,343	0.0%	-5.1%	0	(38,861)	(38,861)	-4.1%
342.00	Fuel Holders, Products and Accessories	750,386	758,487	8,101	0.0%	-5.1%	0	(38,270)	(38,270)	-5.0%
343.00	Prime Movers	76,766	528,037	451,271	0.0%	-5.1%	0	(3,915)	(3,915)	-0.7%
344.00	Generators and Devices	30,772,866	31,682,855	909,989	0.0%	-5.1%	0	(1,569,416)	(1,569,416)	-5.0%
345.00	Accessory Electric Equipment	861,492	2,300,817	1,439,325	0.0%	-5.1%	0	(43,936)	(43,936)	-1.9%
346.00	Miscellaneous Power Plant Equipment	376,605	379,346	2,741	0.0%	-5.1%	0	(19,207)	(19,207)	-5.1%
Total DeMoss Petrie Gas Unit 1		**33,600,103**	**36,590,873**	**2,990,770**	**0.0%**	**-5.1%**	**0**	**(1,713,605)**	**(1,713,605)**	**-4.7%**
Gila River										
341.00	Structures and Improvements	8,508,950	8,508,950	0	0.0%	-4.5%	0	(382,903)	(382,903)	-4.5%
342.00	Fuel Holders, Products and Accessories	6,783,045	6,783,045	0	0.0%	-4.5%	0	(305,237)	(305,237)	-4.5%
343.00	Prime Movers	188,744,730	188,744,730	0	0.0%	-4.5%	0	(8,493,513)	(8,493,513)	-4.5%
344.00	Generators and Devices	32,783,434	32,783,434	0	0.0%	-4.5%	0	(1,475,255)	(1,475,255)	-4.5%
345.00	Accessory Electric Equipment	9,030,698	9,030,698	0	0.0%	-4.5%	0	(406,381)	(406,381)	-4.5%
346.00	Miscellaneous Power Plant Equipment	6,799,960	6,799,960	0	0.0%	-4.5%	0	(305,998)	(305,998)	-4.5%
Total Gila River		**252,650,817**	**252,650,817**	**0**	**0.0%**	**-4.5%**	**0**	**(11,369,287)**	**(11,369,287)**	**-4.5%**
Gila River Unit 3										
341.00	Structures and Improvements	957,417	957,417	0	0.0%	-4.5%	0	(43,084)	(43,084)	-4.5%
342.00	Fuel Holders, Products and Accessories	178,424	178,424	0	0.0%	-4.5%	0	(8,029)	(8,029)	-4.5%
343.00	Prime Movers	181,571,712	181,571,712	0	0.0%	-4.5%	0	(8,170,727)	(8,170,727)	-4.5%
344.00	Generators and Devices	32,783,434	32,783,434	0	0.0%	-4.5%	0	(1,475,255)	(1,475,255)	-4.5%
345.00	Accessory Electric Equipment	6,860,554	6,860,554	0	0.0%	-4.5%	0	(308,725)	(308,725)	-4.5%
346.00	Miscellaneous Power Plant Equipment	135,558	135,558	0	0.0%	-4.5%	0	(6,100)	(6,100)	-4.5%
Total Gila River Unit 3		**222,487,099**	**222,487,099**	**0**	**0.0%**	**-4.5%**	**0**	**(10,011,919)**	**(10,011,919)**	**-4.5%**
Gila River Common										
341.00	Structures and Improvements	7,551,533	7,551,533	0	0.0%	-4.5%	0	(339,819)	(339,819)	-4.5%
342.00	Fuel Holders, Products and Accessories	6,604,621	6,604,621	0	0.0%	-4.5%	0	(297,208)	(297,208)	-4.5%
343.00	Prime Movers	7,173,018	7,173,018	0	0.0%	-4.5%	0	(322,786)	(322,786)	-4.5%
344.00	Generators and Devices	0	0	0	0.0%	0.0%	0	0	0	0.0%

Tucson Electric Power Company
Calculation of Average Net Salvage

Account	Description	12/31/14 Investment	Derived Additions	Calculated Retirements	Salvage Rate Historical	Salvage Rate Future	Calculated Net Salvage Historical	Calculated Net Salvage Future	Calculated Net Salvage Total	Average Rate
345.00	Accessory Electric Equipment	2,170,144	2,170,144	0	0.0%	-4.5%	0	(97,656)	(97,656)	-4.5%
346.00	Miscellaneous Power Plant Equipment	6,664,402	6,664,402	0	0.0%	-4.5%	0	(299,898)	(299,898)	-4.5%
Total Gila River Common		**30,163,718**	**30,163,718**	**0**	**0.0%**	**-4.5%**	**0**	**(1,357,367)**	**(1,357,367)**	**-4.5%**
Luna										
341.00	Structures and Improvements	13,232,832	13,269,836	37,004	0.0%	-9.6%	0	(1,270,352)	(1,270,352)	-9.6%
342.00	Fuel Holders, Products and Accessories	11,352,383	11,352,383	0	0.0%	-9.6%	0	(1,089,829)	(1,089,829)	-9.6%
343.00	Prime Movers	11,151,074	13,516,063	2,364,989	0.0%	-9.6%	0	(1,070,503)	(1,070,503)	-7.9%
344.00	Generators and Devices	9,486,694	16,114,883	6,628,189	0.0%	-9.6%	0	(910,723)	(910,723)	-5.7%
345.00	Accessory Electric Equipment	9,647	9,647	0	0.0%	-9.6%	0	(926)	(926)	-9.6%
346.00	Miscellaneous Power Plant Equipment	7,424,592	7,449,920	25,328	0.0%	-9.6%	0	(712,761)	(712,761)	-9.6%
Total Luna		**52,657,222**	**61,712,732**	**9,055,510**	**0.0%**	**-9.6%**	**0**	**(5,055,093)**	**(5,055,093)**	**-8.2%**
North Loop Gas										
341.00	Structures and Improvements	888,601	891,728	3,127	230.0%	-11.5%	7,192	(102,459)	(95,267)	-10.7%
342.00	Fuel Holders, Products and Accessories	303,037	303,037	0	0.0%	-3.2%	0	(9,697)	(9,697)	-3.2%
343.00	Prime Movers	1,890,946	2,351,487	460,541	0.0%	-12.6%	0	(238,629)	(238,629)	-10.1%
344.00	Generators and Devices	24,062,187	25,738,500	1,676,313	-2.6%	-7.2%	(43,629)	(1,721,788)	(1,765,417)	-6.9%
345.00	Accessory Electric Equipment	2,829,171	3,144,306	315,135	-0.1%	-9.2%	(318)	(260,682)	(261,000)	-8.3%
346.00	Miscellaneous Power Plant Equipment	656,253	735,694	79,441	0.0%	-11.0%	0	(72,409)	(72,409)	-9.8%
Total North Loop Gas		**30,630,195**	**33,164,752**	**2,534,557**	**-1.5%**	**-7.9%**	**(36,755)**	**(2,405,663)**	**(2,442,418)**	**-7.4%**
North Loop Gas Unit 1										
341.00	Structures and Improvements	411,070	411,070	0	0.0%	-11.0%	0	(45,218)	(45,218)	-11.0%
342.00	Fuel Holders, Products and Accessories	0	0	0	0.0%	0.0%	0	0	0	0.0%
343.00	Prime Movers	678,545	685,193	6,648	0.0%	-11.0%	0	(74,640)	(74,640)	-10.9%
344.00	Generators and Devices	3,582,271	3,956,176	373,905	-10.0%	-11.0%	(37,391)	(394,050)	(431,440)	-10.9%
345.00	Accessory Electric Equipment	790,955	808,620	17,665	-0.6%	-11.0%	(106)	(87,005)	(87,111)	-10.8%
346.00	Miscellaneous Power Plant Equipment	306,369	306,369	0	0.0%	-11.0%	0	(33,701)	(33,701)	-11.0%
Total North Loop Gas Unit 1		**5,769,210**	**6,167,428**	**398,218**	**-9.4%**	**-11.0%**	**(37,496)**	**(634,613)**	**(672,110)**	**-10.9%**
North Loop Gas Unit 2										

Tucson Electric Power Company
Calculation of Average Net Salvage

Account	Description	12/31/14 Investment	Derived Additions	Calculated Retirements	Salvage Rate Historical	Salvage Rate Future	Calculated Net Salvage Historical	Calculated Net Salvage Future	Calculated Net Salvage Total	Average Rate
341.00	Structures and Improvements	196,078	196,078	0	0.0%	-14.6%	0	(28,627)	(28,627)	-14.6%
342.00	Fuel Holders, Products and Accessories	0	0	0	0.0%	0.0%	0	0	0	0.0%
343.00	Prime Movers	263,450	676,560	413,110	0.0%	-14.7%	0	(38,727)	(38,727)	-5.7%
344.00	Generators and Devices	3,239,719	3,441,312	201,593	-1.5%	-14.6%	(3,024)	(472,999)	(476,023)	-13.8%
345.00	Accessory Electric Equipment	504,895	522,560	17,665	-0.6%	-14.7%	(106)	(74,220)	(74,326)	-14.2%
346.00	Miscellaneous Power Plant Equipment	128,559	128,559	0	0.0%	-14.6%	0	(18,770)	(18,770)	-14.6%
	Total North Loop Gas Unit 2	**4,332,701**	**4,965,069**	**632,368**	**-0.5%**	**-14.6%**	**(3,130)**	**(633,343)**	**(636,473)**	**-12.8%**
	North Loop Gas Unit 3									
341.00	Structures and Improvements	196,078	196,078	0	0.0%	-13.2%	0	(25,882)	(25,882)	-13.2%
342.00	Fuel Holders, Products and Accessories	0	0	0	0.0%	0.0%	0	0	0	0.0%
343.00	Prime Movers	948,951	989,734	40,783	0.0%	-13.2%	0	(125,262)	(125,262)	-12.7%
344.00	Generators and Devices	3,030,531	3,387,718	357,187	-0.9%	-13.2%	(3,215)	(400,030)	(403,245)	-11.9%
345.00	Accessory Electric Equipment	503,907	521,572	17,665	-0.6%	-13.2%	(106)	(66,516)	(66,622)	-12.8%
346.00	Miscellaneous Power Plant Equipment	128,559	128,559	0	0.0%	-13.2%	0	(16,970)	(16,970)	-13.2%
	Total North Loop Gas Unit 3	**4,808,026**	**5,223,661**	**415,635**	**-0.8%**	**-13.2%**	**(3,321)**	**(634,659)**	**(637,980)**	**-12.2%**
	North Loop Gas Unit 4									
341.00	Structures and Improvements	85,375	88,502	3,127	230.0%	-3.2%	7,192	(2,732)	4,460	5.0%
342.00	Fuel Holders, Products and Accessories	303,037	303,037	0	0.0%	-3.2%	0	(9,697)	(9,697)	-3.2%
343.00	Prime Movers	0	0	0	0.0%	0.0%	0	0	0	0.0%
344.00	Generators and Devices	14,209,666	14,953,294	743,628	0.0%	-3.2%	0	(454,709)	(454,709)	-3.0%
345.00	Accessory Electric Equipment	1,029,414	1,291,554	262,140	0.0%	-3.2%	0	(32,941)	(32,941)	-2.6%
346.00	Miscellaneous Power Plant Equipment	92,766	172,207	79,441	0.0%	-3.2%	0	(2,969)	(2,969)	-1.7%
	Total North Loop Gas Unit 4	**15,720,258**	**16,808,594**	**1,088,336**	**0.7%**	**-3.2%**	**7,192**	**(503,048)**	**(495,856)**	**-3.0%**
	Solar Units (Generators and Devices)									
344.00	DeMoss Petrie	1,146,081	1,146,081	0	0.0%	-5.0%	0	(57,304)	(57,304)	-5.0%
344.00	Fort Huachuca	36,709,538	36,709,538	0	0.0%	-5.0%	0	(1,835,477)	(1,835,477)	-5.0%
344.00	HQ Rooftop	303,184	303,184	0	0.0%	-5.0%	0	(15,159)	(15,159)	-5.0%
344.00	OH Rooftop	2,594,590	2,594,590	0	0.0%	-5.0%	0	(129,730)	(129,730)	-5.0%
344.00	OH Test Yard	388,459	388,459	0	0.0%	-5.0%	0	(19,423)	(19,423)	-5.0%

Tucson Electric Power Company
Calculation of Average Net Salvage

Account	Description	12/31/14 Investment	Derived Additions	Calculated Retirements	Salvage Rate Historical	Salvage Rate Future	Calculated Net Salvage Historical	Calculated Net Salvage Future	Calculated Net Salvage Total	Average Rate
344.00	Prairie Fire	19,036,520	19,036,520	0	0.0%	-5.0%	0	(951,826)	(951,826)	-5.0%
344.00	Springerville Sites 1-3 (Legacy)	28,766,605	28,766,605	0	0.0%	-5.0%	0	(1,438,330)	(1,438,330)	-5.0%
344.00	Springerville Site 4	7,873,874	7,873,874	0	0.0%	-5.0%	0	(393,694)	(393,694)	-5.0%
343.00	Tucson	87,198	87,198	0	0.0%	-5.0%	0	(4,360)	(4,360)	-5.0%
344.00	U of A Tech Park Site 1	7,723,832	7,723,832	0	0.0%	-5.0%	0	(386,192)	(386,192)	-5.0%
345.00	U of A Tech Park Site 2	19,191,952	19,191,952	0	0.0%	-5.0%	0	(959,598)	(959,598)	-5.0%
346.00	White Mountain	46,499,099	46,499,099	0	0.0%	-5.0%	0	(2,324,955)	(2,324,955)	-5.0%
Total Solar Units		**170,320,932**	**170,320,932**	**0**	**0.0%**	**-5.0%**	**0**	**(8,516,047)**	**(8,516,047)**	**-5.0%**
Sundt Gas										
341.00	Structures and Improvements	11,090	12,704	1,614	0.0%	-2.0%	0	(216)	(216)	-1.7%
342.00	Fuel Holders, Products and Accessories	788,336	788,336	0	0.0%	-2.0%	0	(15,373)	(15,373)	-2.0%
343.00	Prime Movers	141,618	141,618	0	0.0%	-2.0%	0	(2,762)	(2,762)	-2.0%
344.00	Generators and Devices	8,382,044	9,148,181	766,137	0.0%	-1.9%	0	(162,827)	(162,827)	-1.8%
345.00	Accessory Electric Equipment	1,078,811	1,109,935	31,124	0.0%	-2.0%	0	(21,153)	(21,153)	-1.9%
346.00	Miscellaneous Power Plant Equipment	49,750	49,750	0	0.0%	-2.0%	0	(995)	(995)	-2.0%
Total Sundt Gas		**10,451,649**	**11,250,524**	**798,875**	**0.0%**	**-1.9%**	**0**	**(203,325)**	**(203,325)**	**-1.8%**
Sundt Gas Unit 1										
341.00	Structures and Improvements	5,545	6,352	807	0.0%	-1.7%	0	(94)	(94)	-1.5%
342.00	Fuel Holders, Products and Accessories	394,168	394,168	0	0.0%	-1.7%	0	(6,701)	(6,701)	-1.7%
343.00	Prime Movers	70,809	70,809	0	0.0%	-1.7%	0	(1,204)	(1,204)	-1.7%
344.00	Generators and Devices	4,315,668	4,531,439	215,771	0.0%	-1.7%	0	(73,366)	(73,366)	-1.6%
345.00	Accessory Electric Equipment	516,231	531,793	15,562	0.0%	-1.7%	0	(8,776)	(8,776)	-1.7%
346.00	Miscellaneous Power Plant Equipment	19,906	19,906	0	0.0%	-1.7%	0	(338)	(338)	-1.7%
Total Sundt Gas Unit 1		**5,322,327**	**5,554,467**	**232,140**	**0.0%**	**-1.7%**	**0**	**(90,480)**	**(90,480)**	**-1.6%**
Sundt Gas Unit 2										
341.00	Structures and Improvements	5,545	6,352	807	0.0%	-2.2%	0	(122)	(122)	-1.9%
342.00	Fuel Holders, Products and Accessories	394,168	394,168	0	0.0%	-2.2%	0	(8,672)	(8,672)	-2.2%
343.00	Prime Movers	70,809	70,809	0	0.0%	-2.2%	0	(1,558)	(1,558)	-2.2%
344.00	Generators and Devices	4,066,376	4,616,742	550,366	0.0%	-2.2%	0	(89,460)	(89,460)	-1.9%

Tucson Electric Power Company
Calculation of Average Net Salvage

Account	Description	12/31/14 Investment	Derived Additions	Calculated Retirements	Salvage Rate Historical	Salvage Rate Future	Calculated Net Salvage Historical	Calculated Net Salvage Future	Calculated Net Salvage Total	Average Rate
345.00	Accessory Electric Equipment	562,580	578,142	15,562	0.0%	-2.2%	0	(12,377)	(12,377)	-2.1%
346.00	Miscellaneous Power Plant Equipment	29,844	29,844	0	0.0%	-2.2%	0	(657)	(657)	-2.2%
Total Sundt Gas Unit 2		**5,129,322**	**5,696,057**	**566,735**	**0.0%**	**-2.2%**	**0**	**(112,845)**	**(112,845)**	**-2.0%**

Tucson Electric Power Company
Calculation of Future Net Salvage for Plants

Account	Description	12/31/14 Investment	Future Retirements Interim	Future Retirements Final	Salvage Rate Interim	Salvage Rate Final	Calculated Net Salvage Interim	Calculated Net Salvage Final	Calculated Net Salvage Total	Future Rate
STEAM PRODUCTION (by Unit)										
Four Corners										
310.00	Rights-of-Way	0	0	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	2,982,777	125,729	2,857,048	-5.0%	-4.8%	(6,286)	(138,452)	(144,738)	-4.9%
312.00	Boiler Plant Equipment	76,402,061	3,267,354	73,134,707	-5.0%	-4.8%	(163,368)	(3,541,453)	(3,704,820)	-4.8%
314.00	Turbogenerator Units	12,359,480	523,849	11,835,631	-5.0%	-4.8%	(26,192)	(569,486)	(595,678)	-4.8%
315.00	Accessory Electric Equipment	4,390,980	180,525	4,210,455	-5.0%	-4.8%	(9,026)	(203,893)	(212,920)	-4.8%
316.00	Miscellaneous Power Plant Equipment	3,832,234	160,207	3,672,027	0.0%	-4.8%	0	(178,084)	(178,084)	-4.6%
Total Four Corners		**99,967,532**	**4,257,665**	**95,709,867**	**-4.8%**	**-4.8%**	**(204,873)**	**(4,631,368)**	**(4,836,241)**	**-4.8%**
Four Corners Unit 4										
310.00	Rights-of-Way	0	0	0	0.0%		0	0	0	0.0%
311.00	Structures and Improvements	1,524,414	64,249	1,460,165	-5.0%	-4.6%	(3,212)	(67,248)	(70,461)	-4.6%
312.00	Boiler Plant Equipment	39,609,538	1,694,925	37,914,613	-5.0%	-4.6%	(84,746)	(1,746,171)	(1,830,917)	-4.6%
314.00	Turbogenerator Units	7,179,362	303,478	6,875,884	-5.0%	-4.6%	(15,174)	(316,671)	(331,845)	-4.6%
315.00	Accessory Electric Equipment	2,274,836	93,584	2,181,252	-5.0%	-4.6%	(4,679)	(100,458)	(105,138)	-4.6%
316.00	Miscellaneous Power Plant Equipment	1,929,161	80,629	1,848,532	0.0%	-4.6%	0	(85,135)	(85,135)	-4.4%
Total Four Corners Unit 4		**52,517,311**	**2,236,864**	**50,280,447**	**-4.8%**	**-4.6%**	**(107,812)**	**(2,315,684)**	**(2,423,496)**	**-4.6%**
Four Corners Unit 5										
310.00	Rights-of-Way	0	0	0	0.0%		0	0	0	0.0%
311.00	Structures and Improvements	1,458,363	61,481	1,396,882	-5.0%	-5.1%	(3,074)	(71,204)	(74,278)	-5.1%
312.00	Boiler Plant Equipment	36,792,523	1,572,430	35,220,093	-5.0%	-5.1%	(78,621)	(1,795,282)	(1,873,903)	-5.1%
314.00	Turbogenerator Units	5,180,118	220,371	4,959,747	-5.0%	-5.1%	(11,019)	(252,814)	(263,833)	-5.1%
315.00	Accessory Electric Equipment	2,116,144	86,942	2,029,202	-5.0%	-5.1%	(4,347)	(103,435)	(107,782)	-5.1%
316.00	Miscellaneous Power Plant Equipment	1,903,073	79,578	1,823,495	0.0%	-5.1%	0	(92,949)	(92,949)	-4.9%
Total Four Corners Unit 5		**47,450,221**	**2,020,801**	**45,429,420**	**-4.8%**	**-5.1%**	**(97,061)**	**(2,315,684)**	**(2,412,745)**	**-5.1%**
Navajo										
310.00	Rights-of-Way	12,229	506	11,723	0.0%	-4.9%	0	(570)	(570)	-4.7%

Tucson Electric Power Company
Calculation of Future Net Salvage for Plants

Account	Description	12/31/14 Investment	Future Retirements Interim	Future Retirements Final	Salvage Rate Interim	Salvage Rate Final	Calculated Net Salvage Interim	Calculated Net Salvage Final	Calculated Net Salvage Total	Future Rate
311.00	Structures and Improvements	18,655,156	647,268	18,007,888	-5.0%	-4.8%	(32,363)	(871,426)	(903,789)	-4.8%
312.00	Boiler Plant Equipment	88,544,201	2,742,632	85,801,569	-5.0%	-4.9%	(137,132)	(4,175,660)	(4,312,791)	-4.9%
314.00	Turbogenerator Units	20,255,526	611,609	19,643,917	-5.0%	-4.9%	(30,580)	(957,892)	(988,472)	-4.9%
315.00	Accessory Electric Equipment	14,829,858	486,654	14,343,204	-5.0%	-4.8%	(24,333)	(694,363)	(718,696)	-4.8%
316.00	Miscellaneous Power Plant Equipment	4,518,597	164,224	4,354,373	0.0%	-4.9%	0	(211,800)	(211,800)	-4.7%
Total Navajo		**146,815,567**	**4,652,894**	**142,162,673**	**-4.8%**	**-4.9%**	**(224,408)**	**(6,911,709)**	**(7,136,117)**	**-4.9%**
Navajo Unit 1										
310.00	Rights-of-Way	0	0	0	0.0%		0	0	0	0.0%
311.00	Structures and Improvements	3,190,563	35,076	3,155,487	-5.0%	-4.8%	(1,754)	(150,404)	(152,157)	-4.8%
312.00	Boiler Plant Equipment	27,198,582	289,406	26,909,176	-5.0%	-4.8%	(14,470)	(1,282,604)	(1,297,074)	-4.8%
314.00	Turbogenerator Units	6,860,989	73,135	6,787,854	-5.0%	-4.8%	(3,657)	(323,537)	(327,194)	-4.8%
315.00	Accessory Electric Equipment	3,544,300	37,858	3,506,442	-5.0%	-4.8%	(1,893)	(167,132)	(169,025)	-4.8%
316.00	Miscellaneous Power Plant Equipment	471,227	5,200	466,027	0.0%	-4.8%	0	(22,213)	(22,213)	-4.7%
Total Navajo Unit 1		**41,265,661**	**440,676**	**40,824,985**	**-4.9%**	**-4.8%**	**(21,774)**	**(1,945,889)**	**(1,967,663)**	**-4.8%**
Navajo Unit 2										
310.00	Rights-of-Way	0	0	0	0.0%		0	0	0	0.0%
311.00	Structures and Improvements	1,802,685	73,142	1,729,543	-5.0%	-5.2%	(3,657)	(89,224)	(92,881)	-5.2%
312.00	Boiler Plant Equipment	26,882,286	1,080,667	25,801,619	-5.0%	-5.2%	(54,033)	(1,331,054)	(1,385,088)	-5.2%
314.00	Turbogenerator Units	6,926,050	277,187	6,648,863	-5.0%	-5.2%	(13,859)	(343,002)	(356,861)	-5.2%
315.00	Accessory Electric Equipment	3,172,330	127,256	3,045,074	-5.0%	-5.2%	(6,363)	(157,089)	(163,452)	-5.2%
316.00	Miscellaneous Power Plant Equipment	515,874	21,188	494,686	0.0%	-5.2%	0	(25,520)	(25,520)	-4.9%
Total Navajo Unit 2		**39,299,225**	**1,579,440**	**37,719,785**	**-4.9%**	**-5.2%**	**(77,913)**	**(1,945,889)**	**(2,023,802)**	**-5.1%**
Navajo Unit 3										
310.00	Rights-of-Way	0	0	0	0.0%		0	0	0	0.0%
311.00	Structures and Improvements	3,681,511	150,256	3,531,255	-5.0%	-4.7%	(7,513)	(165,471)	(172,983)	-4.7%
312.00	Boiler Plant Equipment	27,718,514	1,110,320	26,608,194	-5.0%	-4.7%	(55,516)	(1,246,830)	(1,302,346)	-4.7%
314.00	Turbogenerator Units	6,178,944	250,312	5,928,632	-5.0%	-4.7%	(12,516)	(277,809)	(290,325)	-4.7%

Tucson Electric Power Company
Calculation of Future Net Salvage for Plants

Account	Description	12/31/14 Investment	Future Retirements Interim	Future Retirements Final	Salvage Rate Interim	Salvage Rate Final	Calculated Net Salvage Interim	Calculated Net Salvage Final	Calculated Net Salvage Total	Future Rate
315.00	Accessory Electric Equipment	5,139,872	208,272	4,931,600	-5.0%	-4.7%	(10,414)	(231,089)	(241,503)	-4.7%
316.00	Miscellaneous Power Plant Equipment	549,362	22,448	526,914	0.0%	-4.7%	0	(24,691)	(24,691)	-4.5%
Total Navajo Unit 3		**43,268,203**	**1,741,608**	**41,526,595**	**-4.9%**	**-4.7%**	**(85,958)**	**(1,945,889)**	**(2,031,847)**	**-4.7%**
Navajo Common										
310.00	Rights-of-Way	12,229	506	11,723	0.0%	-4.9%	0	(570)	(570)	-4.7%
311.00	Structures and Improvements	9,980,397	388,794	9,591,603	-5.0%	-4.9%	(19,440)	(466,328)	(485,767)	-4.9%
312.00	Boiler Plant Equipment	6,744,819	262,239	6,482,580	-5.0%	-4.9%	(13,112)	(315,172)	(328,284)	-4.9%
314.00	Turbogenerator Units	289,543	10,974	278,569	-5.0%	-4.9%	(549)	(13,544)	(14,092)	-4.9%
315.00	Accessory Electric Equipment	2,973,356	113,268	2,860,088	-5.0%	-4.9%	(5,663)	(139,053)	(144,716)	-4.9%
316.00	Miscellaneous Power Plant Equipment	2,982,134	115,388	2,866,746	0.0%	-4.9%	0	(139,376)	(139,376)	-4.7%
Total Navajo Common		**22,982,478**	**891,170**	**22,091,308**	**-4.3%**	**-4.9%**	**(38,764)**	**(1,074,042)**	**(1,112,806)**	**-4.8%**
San Juan										
310.00	Rights-of-Way	0	0	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	14,437,744	463,504	13,974,240	-5.0%	-8.0%	(23,175)	(1,114,553)	(1,137,728)	-7.9%
312.00	Boiler Plant Equipment	154,506,908	4,871,333	149,635,575	-5.0%	-9.8%	(243,567)	(14,676,449)	(14,920,015)	-9.7%
314.00	Turbogenerator Units	44,295,673	1,411,705	42,883,968	-5.0%	-8.1%	(70,585)	(3,461,006)	(3,531,591)	-8.0%
315.00	Accessory Electric Equipment	10,063,526	319,494	9,744,032	-5.0%	-8.1%	(15,975)	(786,405)	(802,379)	-8.0%
316.00	Miscellaneous Power Plant Equipment	2,009,555	63,827	1,945,728	0.0%	-7.9%	0	(153,167)	(153,167)	-7.6%
Total San Juan		**225,313,406**	**7,129,861**	**218,183,545**	**-5.0%**	**-9.3%**	**(353,302)**	**(20,191,578)**	**(20,544,880)**	**-9.1%**
San Juan Unit 1										
310.00	Rights-of-Way	0	0	0	0.0%		0	0	0	0.0%
311.00	Structures and Improvements	14,268,404	458,417	13,809,987	-5.0%	-8.1%	(22,921)	(1,114,553)	(1,137,474)	-8.0%
312.00	Boiler Plant Equipment	146,453,029	4,622,894	141,830,135	-5.0%	-8.1%	(231,145)	(11,446,582)	(11,677,727)	-8.0%
314.00	Turbogenerator Units	44,295,673	1,411,705	42,883,968	-5.0%	-8.1%	(70,585)	(3,461,006)	(3,531,591)	-8.0%
315.00	Accessory Electric Equipment	10,063,526	319,494	9,744,032	-5.0%	-8.1%	(15,975)	(786,405)	(802,379)	-8.0%
316.00	Miscellaneous Power Plant Equipment	1,960,172	62,343	1,897,829	0.0%	-8.1%	0	(153,167)	(153,167)	-7.8%
Total San Juan Unit 1		**217,040,804**	**6,874,853**	**210,165,951**	**-5.0%**	**-8.1%**	**(340,625)**	**(16,961,712)**	**(17,302,337)**	**-8.0%**

Tucson Electric Power Company
Calculation of Future Net Salvage for Plants

Account	Description	12/31/14 Investment	Future Retirements Interim	Future Retirements Final	Salvage Rate Interim	Salvage Rate Final	Calculated Net Salvage Interim	Calculated Net Salvage Final	Calculated Net Salvage Total	Future Rate
315.00	Accessory Electric Equipment	0	0	0	0.0%	-33.8%	0	0	0	0.0%
316.00	Miscellaneous Power Plant Equipment	0	0	0	0.0%	-33.8%	0	0	0	0.0%
Total Springerville Coal Handling		**140,614,901**	**13,198,444**	**127,416,457**	**-4.9%**	**-33.4%**	**(652,012)**	**(42,610,245)**	**(43,262,257)**	**-30.8%**
Sundt										
310.00	Rights-of-Way	0	0	0	0.0%	0.0%	0	0	0	0.0%
311.00	Structures and Improvements	27,475,371	2,009,394	25,465,977	-5.0%	-31.2%	(100,470)	(7,952,968)	(8,053,437)	-29.3%
312.00	Boiler Plant Equipment	130,812,626	9,768,195	121,044,431	-5.0%	-28.5%	(488,410)	(34,525,799)	(35,014,209)	-26.8%
314.00	Turbogenerator Units	52,481,329	3,139,546	49,341,783	-5.0%	-42.0%	(156,977)	(20,737,140)	(20,894,118)	-39.8%
315.00	Accessory Electric Equipment	39,432,489	2,508,541	36,923,948	-5.0%	-36.1%	(125,427)	(13,319,158)	(13,444,585)	-34.1%
316.00	Miscellaneous Power Plant Equipment	2,333,493	139,906	2,193,587	0.0%	-38.3%	0	(841,136)	(841,136)	-36.0%
Total Sundt		**252,535,308**	**17,565,582**	**234,969,726**	**-5.0%**	**-32.9%**	**(871,284)**	**(77,376,202)**	**(78,247,486)**	**-31.0%**
Sundt Unit 1										
310.00	Rights-of-Way	0	0	0	0.0%		0	0	0	0.0%
311.00	Structures and Improvements	3,926,062	178,099	3,747,963	-5.0%	-49.1%	(8,905)	(1,842,099)	(1,851,004)	-47.1%
312.00	Boiler Plant Equipment	13,782,181	616,552	13,165,629	-5.0%	-49.1%	(30,828)	(6,470,818)	(6,501,646)	-47.2%
314.00	Turbogenerator Units	10,237,507	457,972	9,779,535	-5.0%	-49.1%	(22,899)	(4,806,575)	(4,829,474)	-47.2%
315.00	Accessory Electric Equipment	6,536,315	216,750	6,319,565	-5.0%	-49.1%	(10,838)	(3,106,023)	(3,116,861)	-47.7%
316.00	Miscellaneous Power Plant Equipment	490,578	16,412	474,166	0.0%	-49.1%	0	(233,049)	(233,049)	-47.5%
Total Sundt Unit 1		**34,972,643**	**1,485,786**	**33,486,857**	**-4.9%**	**-49.1%**	**(73,469)**	**(16,458,565)**	**(16,532,033)**	**-47.3%**
Sundt Unit 2										
310.00	Rights-of-Way	0	0	0	0.0%		0	0	0	0.0%
311.00	Structures and Improvements	2,812,689	124,859	2,687,830	-5.0%	-53.4%	(6,243)	(1,435,678)	(1,441,921)	-51.3%
312.00	Boiler Plant Equipment	14,371,609	648,068	13,723,541	-5.0%	-53.4%	(32,403)	(7,330,293)	(7,362,697)	-51.2%
314.00	Turbogenerator Units	8,451,923	388,171	8,063,752	-5.0%	-53.4%	(19,409)	(4,307,173)	(4,326,582)	-51.2%
315.00	Accessory Electric Equipment	6,205,700	236,730	5,968,970	-5.0%	-53.4%	(11,837)	(3,188,266)	(3,200,103)	-51.6%
316.00	Miscellaneous Power Plant Equipment	383,824	14,718	369,106	0.0%	-53.4%	0	(197,154)	(197,154)	-51.4%
Total Sundt Unit 2		**32,225,745**	**1,412,545**	**30,813,200**	**-4.9%**	**-53.4%**	**(69,891)**	**(16,458,565)**	**(16,528,456)**	**-51.3%**

Tucson Electric Power Company
Calculation of Future Net Salvage for Plants

Account	Description	12/31/14 Investment	Future Retirements Interim	Future Retirements Final	Salvage Rate Interim	Salvage Rate Final	Calculated Net Salvage Interim	Calculated Net Salvage Final	Calculated Net Salvage Total	Future Rate
Sundt Unit 3										
310.00	Rights-of-Way	0	0	0	0.0%		0	0	0	0.0%
311.00	Structures and Improvements	2,762,012	124,459	2,637,553	-5.0%	-58.7%	(6,223)	(1,548,491)	(1,554,714)	-56.3%
312.00	Boiler Plant Equipment	11,980,831	543,246	11,437,585	-5.0%	-58.7%	(27,162)	(6,714,937)	(6,742,099)	-56.3%
314.00	Turbogenerator Units	14,830,615	662,973	14,167,642	-5.0%	-58.7%	(33,149)	(8,317,737)	(8,350,886)	-56.3%
315.00	Accessory Electric Equipment	6,140,139	271,786	5,868,353	-5.0%	-58.7%	(13,589)	(3,445,275)	(3,458,864)	-56.3%
316.00	Miscellaneous Power Plant Equipment	404,717	17,752	386,965	0.0%	-58.7%	0	(227,185)	(227,185)	-56.1%
Total Sundt Unit 3		**36,118,314**	**1,620,216**	**34,498,098**	**-4.9%**	**-58.7%**	**(80,123)**	**(20,253,625)**	**(20,333,748)**	**-56.3%**
Sundt Unit 4										
310.00	Rights-of-Way	0	0	0	0.0%		0	0	0	0.0%
311.00	Structures and Improvements	17,974,608	1,581,977	16,392,631	-5.0%	-19.1%	(79,099)	(3,126,700)	(3,205,799)	-17.8%
312.00	Boiler Plant Equipment	80,576,055	7,125,872	73,450,183	-5.0%	-19.1%	(356,294)	(14,009,751)	(14,366,045)	-17.8%
314.00	Turbogenerator Units	18,961,284	1,630,429	17,330,855	-5.0%	-19.1%	(81,521)	(3,305,655)	(3,387,176)	-17.9%
315.00	Accessory Electric Equipment	20,550,335	1,783,275	18,767,060	-5.0%	-19.1%	(89,164)	(3,579,594)	(3,668,758)	-17.9%
316.00	Miscellaneous Power Plant Equipment	1,054,374	91,024	963,350	0.0%	-19.1%	0	(183,748)	(183,748)	-17.4%
Total Sundt Unit 4		**139,116,656**	**12,212,578**	**126,904,078**	**-5.0%**	**-19.1%**	**(606,078)**	**(24,205,448)**	**(24,811,525)**	**-17.8%**
Sundt Solar Booster (Areva)										
310.00	Rights-of-Way	0	0	0	0.0%		0	0	0	0.0%
311.00	Structures and Improvements	0	0	0	0.0%		0	0	0	0.0%
312.00	Boiler Plant Equipment	10,101,950	834,456	9,267,494	-5.0%		(41,723)	0	(41,723)	-0.4%
314.00	Turbogenerator Units	0	0	0	0.0%		0	0	0	0.0%
315.00	Accessory Electric Equipment	0	0	0	0.0%		0	0	0	0.0%
316.00	Miscellaneous Power Plant Equipment	0	0	0	0.0%		0	0	0	0.0%
Total Sundt Solar Booster (Areva)		**10,101,950**	**834,456**	**9,267,494**	**-5.0%**	**0.0%**	**(41,723)**	**0**	**(41,723)**	**-0.4%**

OTHER PRODUCTION (by Unit)

Tucson Electric Power Company
Calculation of Future Net Salvage for Plants

Account	Description	12/31/14 Investment	Future Retirements Interim	Future Retirements Final	Salvage Rate Interim	Salvage Rate Final	Calculated Net Salvage Interim	Calculated Net Salvage Final	Calculated Net Salvage Total	Future Rate
DeMoss Petrie Gas Unit 1										
341.00	Structures and Improvements	761,988	60,324	701,664	0.0%	-5.5%	0	(38,733)	(38,733)	-5.1%
342.00	Fuel Holders, Products and Accessories	750,386	60,186	690,200	0.0%	-5.5%	0	(38,101)	(38,101)	-5.1%
343.00	Prime Movers	76,766	6,017	70,749	0.0%	-5.5%	0	(3,906)	(3,906)	-5.1%
344.00	Generators and Devices	30,772,866	2,467,553	28,305,313	0.0%	-5.5%	0	(1,562,517)	(1,562,517)	-5.1%
345.00	Accessory Electric Equipment	861,492	68,973	792,519	0.0%	-5.5%	0	(43,749)	(43,749)	-5.1%
346.00	Miscellaneous Power Plant Equipment	376,605	30,058	346,547	0.0%	-5.5%	0	(19,130)	(19,130)	-5.1%
Total DeMoss Petrie Gas Unit 1		**33,600,103**	**2,693,110**	**30,906,993**	**0.0%**	**-5.5%**	**0**	**(1,706,136)**	**(1,706,136)**	**-5.1%**
Gila River										
341.00	Structures and Improvements	8,508,950	722,006	7,786,944	0.0%	-4.9%	0	(384,369)	(384,369)	-4.5%
342.00	Fuel Holders, Products and Accessories	6,783,045	575,960	6,207,085	0.0%	-4.9%	0	(306,538)	(306,538)	-4.5%
343.00	Prime Movers	188,744,730	15,990,013	172,754,717	0.0%	-4.9%	0	(8,485,805)	(8,485,805)	-4.5%
344.00	Generators and Devices	32,783,434	2,784,699	29,998,735	0.0%	-4.9%	0	(1,473,232)	(1,473,232)	-4.5%
345.00	Accessory Electric Equipment	9,030,698	766,677	8,264,021	0.0%	-4.9%	0	(406,406)	(406,406)	-4.5%
346.00	Miscellaneous Power Plant Equipment	6,799,960	577,149	6,222,811	0.0%	-4.9%	0	(307,325)	(307,325)	-4.5%
Total Gila River		**252,650,817**	**21,416,503**	**231,234,314**	**0.0%**	**-4.9%**	**0**	**(11,363,674)**	**(11,363,674)**	**-4.5%**
Gila River Unit 3										
341.00	Structures and Improvements	957,417	81,280	876,137	0.0%	-4.9%	0	(43,027)	(43,027)	-4.5%
342.00	Fuel Holders, Products and Accessories	178,424	15,110	163,314	0.0%	-4.9%	0	(8,020)	(8,020)	-4.5%
343.00	Prime Movers	181,571,712	15,386,002	166,185,710	0.0%	-4.9%	0	(8,161,345)	(8,161,345)	-4.5%
344.00	Generators and Devices	32,783,434	2,784,699	29,998,735	0.0%	-4.9%	0	(1,473,232)	(1,473,232)	-4.5%
345.00	Accessory Electric Equipment	6,860,554	582,436	6,278,118	0.0%	-4.9%	0	(308,317)	(308,317)	-4.5%
346.00	Miscellaneous Power Plant Equipment	135,558	11,493	124,065	0.0%	-4.9%	0	(6,093)	(6,093)	-4.5%
Total Gila River Unit 3		**222,487,099**	**18,861,018**	**203,626,081**	**0.0%**	**-4.9%**	**0**	**(10,000,034)**	**(10,000,034)**	**-4.5%**
Gila River Common										
341.00	Structures and Improvements	7,551,533	640,726	6,910,807	0.0%	-4.9%	0	(341,342)	(341,342)	-4.5%
342.00	Fuel Holders, Products and Accessories	6,604,621	560,850	6,043,771	0.0%	-4.9%	0	(298,517)	(298,517)	-4.5%

Tucson Electric Power Company
Calculation of Future Net Salvage for Plants

Account	Description	12/31/14 Investment	Future Retirements Interim	Future Retirements Final	Salvage Rate Interim	Salvage Rate Final	Calculated Net Salvage Interim	Calculated Net Salvage Final	Calculated Net Salvage Total	Future Rate
343.00	Prime Movers	7,173,018	604,011	6,569,007	0.0%	-4.9%	0	(324,460)	(324,460)	-4.5%
344.00	Generators and Devices	0	0	0	0.0%	-4.9%	0	0	0	0.0%
345.00	Accessory Electric Equipment	2,170,144	184,242	1,985,902	0.0%	-4.9%	0	(98,089)	(98,089)	-4.5%
346.00	Miscellaneous Power Plant Equipment	6,664,402	565,656	6,098,746	0.0%	-4.9%	0	(301,233)	(301,233)	-4.5%
Total Gila River Common		**30,163,718**	**2,555,485**	**27,608,233**	**0.0%**	**-4.9%**	**0**	**(1,363,641)**	**(1,363,641)**	**-4.5%**
Luna										
341.00	Structures and Improvements	13,232,832	1,216,311	12,016,521	0.0%	-10.6%	0	(1,268,864)	(1,268,864)	-9.6%
342.00	Fuel Holders, Products and Accessories	11,352,383	1,043,899	10,308,484	0.0%	-10.6%	0	(1,088,506)	(1,088,506)	-9.6%
343.00	Prime Movers	11,151,074	1,011,828	10,139,246	0.0%	-10.6%	0	(1,070,636)	(1,070,636)	-9.6%
344.00	Generators and Devices	9,486,694	871,757	8,614,937	0.0%	-10.6%	0	(909,679)	(909,679)	-9.6%
345.00	Accessory Electric Equipment	9,647	869	8,778	0.0%	-10.6%	0	(927)	(927)	-9.6%
346.00	Miscellaneous Power Plant Equipment	7,424,592	682,593	6,741,999	0.0%	-10.6%	0	(711,910)	(711,910)	-9.6%
Total Luna		**52,657,222**	**4,827,258**	**47,829,964**	**0.0%**	**-10.6%**	**0**	**(5,050,522)**	**(5,050,522)**	**-9.6%**
North Loop Gas										
341.00	Structures and Improvements	888,601	43,699	844,902	0.0%	-12.1%	0	(102,602)	(102,602)	-11.5%
342.00	Fuel Holders, Products and Accessories	303,037	24,306	278,731	0.0%	-3.5%	0	(9,789)	(9,789)	-3.2%
343.00	Prime Movers	1,890,946	81,057	1,809,889	0.0%	-13.2%	0	(239,344)	(239,344)	-12.7%
344.00	Generators and Devices	24,062,187	1,599,248	22,462,939	0.0%	-7.7%	0	(1,727,128)	(1,727,128)	-7.2%
345.00	Accessory Electric Equipment	2,829,171	164,276	2,664,895	0.0%	-9.8%	0	(260,899)	(260,899)	-9.2%
346.00	Miscellaneous Power Plant Equipment	656,253	33,556	622,697	0.0%	-11.6%	0	(72,478)	(72,478)	-11.0%
Total North Loop Gas		**30,630,195**	**1,946,142**	**28,684,053**	**0.0%**	**-8.4%**	**0**	**(2,412,240)**	**(2,412,240)**	**-7.9%**
North Loop Gas Unit 1										
341.00	Structures and Improvements	411,070	18,567	392,503	0.0%	-11.5%	0	(45,256)	(45,256)	-11.0%
342.00	Fuel Holders, Products and Accessories	0	0	0	0.0%	-11.5%	0	0	0	0.0%
343.00	Prime Movers	678,545	29,433	649,112	0.0%	-11.5%	0	(74,843)	(74,843)	-11.0%
344.00	Generators and Devices	3,582,271	166,023	3,416,248	0.0%	-11.5%	0	(393,896)	(393,896)	-11.0%
345.00	Accessory Electric Equipment	790,955	35,693	755,262	0.0%	-11.5%	0	(87,082)	(87,082)	-11.0%

Tucson Electric Power Company
Calculation of Future Net Salvage for Plants

Account	Description	12/31/14 Investment	Future Retirements Interim	Future Retirements Final	Salvage Rate Interim	Salvage Rate Final	Calculated Net Salvage Interim	Calculated Net Salvage Final	Calculated Net Salvage Total	Future Rate
346.00	Miscellaneous Power Plant Equipment	306,369	13,892	292,477	0.0%	-11.5%	0	(33,723)	(33,723)	-11.0%
Total North Loop Gas Unit 1		**5,769,210**	**263,608**	**5,505,602**	**0.0%**	**-11.5%**	**0**	**(634,800)**	**(634,800)**	**-11.0%**
North Loop Gas Unit 2										
341.00	Structures and Improvements	196,078	9,155	186,923	0.0%	-15.4%	0	(28,717)	(28,717)	-14.6%
342.00	Fuel Holders, Products and Accessories	0	0	0	0.0%	-15.4%	0	0	0	0.0%
343.00	Prime Movers	263,450	10,722	252,728	0.0%	-15.4%	0	(38,826)	(38,826)	-14.7%
344.00	Generators and Devices	3,239,719	151,505	3,088,214	0.0%	-15.4%	0	(474,435)	(474,435)	-14.6%
345.00	Accessory Electric Equipment	504,895	23,143	481,752	0.0%	-15.4%	0	(74,011)	(74,011)	-14.7%
346.00	Miscellaneous Power Plant Equipment	128,559	6,112	122,447	0.0%	-15.4%	0	(18,811)	(18,811)	-14.6%
Total North Loop Gas Unit 2		**4,332,701**	**200,637**	**4,132,064**	**0.0%**	**-15.4%**	**0**	**(634,800)**	**(634,800)**	**-14.7%**
North Loop Gas Unit 3										
341.00	Structures and Improvements	196,078	9,155	186,923	0.0%	-13.8%	0	(25,870)	(25,870)	-13.2%
342.00	Fuel Holders, Products and Accessories	0	0	0	0.0%	-13.8%	0	0	0	0.0%
343.00	Prime Movers	948,951	40,902	908,049	0.0%	-13.8%	0	(125,675)	(125,675)	-13.2%
344.00	Generators and Devices	3,030,531	142,091	2,888,440	0.0%	-13.8%	0	(399,763)	(399,763)	-13.2%
345.00	Accessory Electric Equipment	503,907	23,100	480,807	0.0%	-13.8%	0	(66,544)	(66,544)	-13.2%
346.00	Miscellaneous Power Plant Equipment	128,559	6,112	122,447	0.0%	-13.8%	0	(16,947)	(16,947)	-13.2%
Total North Loop Gas Unit 3		**4,808,026**	**221,360**	**4,586,666**	**0.0%**	**-13.8%**	**0**	**(634,800)**	**(634,800)**	**-13.2%**
North Loop Gas Unit 4										
341.00	Structures and Improvements	85,375	6,822	78,553	0.0%	-3.5%	0	(2,759)	(2,759)	-3.2%
342.00	Fuel Holders, Products and Accessories	303,037	24,306	278,731	0.0%	-3.5%	0	(9,789)	(9,789)	-3.2%
343.00	Prime Movers	0	0	0	0.0%	-3.5%	0	0	0	0.0%
344.00	Generators and Devices	14,209,666	1,139,629	13,070,037	0.0%	-3.5%	0	(459,033)	(459,033)	-3.2%
345.00	Accessory Electric Equipment	1,029,414	82,340	947,074	0.0%	-3.5%	0	(33,262)	(33,262)	-3.2%
346.00	Miscellaneous Power Plant Equipment	92,766	7,441	85,325	0.0%	-3.5%	0	(2,997)	(2,997)	-3.2%
Total North Loop Gas Unit 4		**15,720,258**	**1,260,537**	**14,459,721**	**0.0%**	**-3.5%**	**0**	**(507,840)**	**(507,840)**	**-3.2%**

Tucson Electric Power Company
Calculation of Future Net Salvage for Plants

Account	Description	12/31/14 Investment	Future Retirements Interim	Future Retirements Final	Salvage Rate Interim	Salvage Rate Final	Calculated Net Salvage Interim	Calculated Net Salvage Final	Calculated Net Salvage Total	Future Rate
Solar Units (Generators and Devices)										
344.00	DeMoss Petrie	1,146,081	1,146,081	0	-5.0%		(57,304)	0	(57,304)	-5.0%
344.00	Fort Huachuca	36,709,538	36,709,538	0	-5.0%		(1,835,477)	0	(1,835,477)	-5.0%
344.00	HQ Rooftop	303,184	303,184	0	-5.0%		(15,159)	0	(15,159)	-5.0%
344.00	OH Rooftop	2,594,590	2,594,590	0	-5.0%		(129,730)	0	(129,730)	-5.0%
344.00	OH Test Yard	388,459	388,459	0	-5.0%		(19,423)	0	(19,423)	-5.0%
344.00	Prairie Fire	19,036,520	19,036,520	0	-5.0%		(951,826)	0	(951,826)	-5.0%
344.00	Springerville Sites 1-3 (Legacy)	28,766,605	28,766,605	0	-5.0%		(1,438,330)	0	(1,438,330)	-5.0%
344.00	Springerville Site 4	7,873,874	7,873,874	0	-5.0%		(393,694)	0	(393,694)	-5.0%
343.00	Tucson	87,198	87,198	0	-5.0%		(4,360)	0	(4,360)	-5.0%
344.00	U of A Tech Park Site 1	7,723,832	7,723,832	0	-5.0%		(386,192)	0	(386,192)	-5.0%
345.00	U of A Tech Park Site 2	19,191,952	19,191,952	0	-5.0%		(959,598)	0	(959,598)	-5.0%
346.00	White Mountain	46,499,099	46,499,099	0	-5.0%		(2,324,955)	0	(2,324,955)	-5.0%
Total Solar Units		**170,320,932**	**170,320,932**	**0**	**-5.0%**		**(8,516,047)**	**0**	**(8,516,047)**	**-5.0%**
Sundt Gas										
341.00	Structures and Improvements	11,090	511	10,579	0.0%	-1.8%	0	(194)	(194)	-1.8%
342.00	Fuel Holders, Products and Accessories	788,336	34,265	754,071	0.0%	-1.8%	0	(13,836)	(13,836)	-1.8%
343.00	Prime Movers	141,618	6,229	135,389	0.0%	-1.8%	0	(2,484)	(2,484)	-1.8%
344.00	Generators and Devices	8,382,044	389,138	7,992,906	0.0%	-1.8%	0	(146,572)	(146,572)	-1.7%
345.00	Accessory Electric Equipment	1,078,811	49,719	1,029,092	0.0%	-1.8%	0	(18,897)	(18,897)	-1.8%
346.00	Miscellaneous Power Plant Equipment	49,750	2,354	47,396	0.0%	-1.8%	0	(873)	(873)	-1.8%
Total Sundt Gas		**10,451,649**	**482,216**	**9,969,433**	**0.0%**	**-1.8%**	**0**	**(182,855)**	**(182,855)**	**-1.7%**
Sundt Gas Unit 1										
341.00	Structures and Improvements	5,545	255	5,290	0.0%	-1.8%	0	(95)	(95)	-1.7%
342.00	Fuel Holders, Products and Accessories	394,168	17,132	377,036	0.0%	-1.8%	0	(6,790)	(6,790)	-1.7%
343.00	Prime Movers	70,809	3,115	67,694	0.0%	-1.8%	0	(1,219)	(1,219)	-1.7%
344.00	Generators and Devices	4,315,668	200,556	4,115,112	0.0%	-1.8%	0	(74,113)	(74,113)	-1.7%
345.00	Accessory Electric Equipment	516,231	23,846	492,385	0.0%	-1.8%	0	(8,868)	(8,868)	-1.7%

Tucson Electric Power Company
Calculation of Future Net Salvage for Plants

Account	Description	12/31/14 Investment	Future Retirements Interim	Future Retirements Final	Salvage Rate Interim	Salvage Rate Final	Calculated Net Salvage Interim	Calculated Net Salvage Final	Calculated Net Salvage Total	Future Rate
346.00	Miscellaneous Power Plant Equipment	19,906	944	18,962	0.0%	-1.8%	0	(342)	(342)	-1.7%
Total Sundt Gas Unit 1		**5,322,327**	**245,847**	**5,076,480**	**0.0%**	**-1.8%**	**0**	**(91,427)**	**(91,427)**	**-1.7%**
Sundt Gas Unit 2										
341.00	Structures and Improvements	5,545	255	5,290	0.0%	-1.9%	0	(99)	(99)	-1.8%
342.00	Fuel Holders, Products and Accessories	394,168	17,132	377,036	0.0%	-1.9%	0	(7,045)	(7,045)	-1.8%
343.00	Prime Movers	70,809	3,115	67,694	0.0%	-1.9%	0	(1,265)	(1,265)	-1.8%
344.00	Generators and Devices	4,066,376	188,582	3,877,794	0.0%	-1.9%	0	(72,459)	(72,459)	-1.8%
345.00	Accessory Electric Equipment	562,580	25,874	536,706	0.0%	-1.9%	0	(10,029)	(10,029)	-1.8%
346.00	Miscellaneous Power Plant Equipment	29,844	1,411	28,433	0.0%	-1.9%	0	(531)	(531)	-1.8%
Total Sundt Gas Unit 2		**5,129,322**	**236,369**	**4,892,953**	**0.0%**	**-1.8%**	**0**	**(91,427)**	**(91,427)**	**-1.8%**

Tucson Electric Power Company
Dismantlement Costs for Plants

Account	Description	12/31/14 Investment	Capacity (MW)	Ownership Share	Share of Distmantlement Cost	Estimated Final Retirement Amount	Distributed Distmantlement Cost	Inflation Rate	Effective Rate Year	Inflated Distmantlement Cost	Accrual Rate
STEAM PRODUCTION (by Unit)											
Four Corners											
	Unit 4	52,517,311	785	7.00%		50,280,447	2,225,763	2.00%	2017	2,315,684	4.6%
	Unit 5	47,450,221	785	7.00%		45,429,420	2,225,763	2.00%	2017	2,315,684	5.1%
	Common			5.07%				2.00%	2017	0	0.0%
Total Four Corners		**99,967,532**	**1570**		**4,451,526**	**95,709,867**	**4,451,526**			**4,631,368**	**4.8%**
Navajo											
	Unit 1	41,265,661	750	7.50%		40,824,985	1,727,894	2.00%	2017	1,945,889	4.8%
	Unit 2	39,299,225	750	7.50%		37,719,785	1,727,894	2.00%	2017	1,945,889	5.2%
	Unit 3	43,268,203	750	7.50%		41,526,595	1,727,894	2.00%	2017	1,945,889	4.7%
	Common	22,982,478				22,091,308	953,719	2.00%	2017	1,074,042	4.9%
Total Navajo		**146,815,567**	**2250**		**6,137,400**	**142,162,673**	**6,137,400**			**6,911,709**	**4.9%**
San Juan											
	Unit 1	217,040,804	340	50.00%		210,165,951	15,670,000	2.00%	2017	16,961,712	8.1%
	Common	8,272,602		50.00%		8,017,593	3,065,000	2.00%	2017	3,317,655	41.4%
Total San Juan		**225,313,406**	**340**		**18,735,000**	**218,183,545**	**18,735,000**			**20,279,367**	**9.3%**
Springerville											
	Unit 1	279,797,726	387	49.50%	7,211,620	257,490,499	7,211,620	2.00%	2017	8,121,456	3.2%
	Unit 1C	81,341,552		49.50%	6,810,975	74,831,289	6,810,975	2.00%	2017	7,670,264	10.3%
	Unit 2	503,489,531	390	100.00%	14,568,930	457,393,593	14,568,930	2.00%	2017	16,406,981	3.6%
	Unit 2C	45,308,246		100.00%	13,759,545	44,242,199	13,759,545	2.00%	2017	15,495,482	35.0%
	CH	140,614,901		49.28%	38,291,033	127,416,457	38,291,033	2.00%	2017	43,121,922	33.8%
Total Springerville		**1,050,551,956**	**777**		**80,642,103**	**961,374,037**	**80,642,103**			**90,816,106**	**9.4%**
Sundt											

Tucson Electric Power Company
Dismantlement Costs for Plants

Account	Description	12/31/14 Investment	Capacity (MW)	Ownership Share	Share of Distmantlement Cost	Estimated Final Retirement Amount	Distributed Distmantlement Cost	Inflation Rate	Effective Rate Year	Inflated Distmantlement Cost	Accrual Rate
	Unit 1	34,972,643	81	100.00%	5,501,274	33,486,857	14,614,734	2.00%	2017	16,458,565	49.1%
	Unit 2	32,225,745	81	100.00%	5,501,274	30,813,200	14,614,734	2.00%	2017	16,458,565	53.4%
	Unit 3	36,118,314	104	100.00%	6,283,406	34,498,098	17,984,639	2.00%	2017	20,253,625	58.7%
	Unit 4	139,116,656	120	100.00%	7,992,322	126,904,078	21,493,745	2.00%	2017	24,205,448	19.1%
	Common				43,429,577					0	0.0%
Total Sundt		**242,433,358**	**386**		**68,707,853**	**225,702,232**	**68,707,853**			**77,376,202**	**34.3%**
OTHER PRODUCTION (by Unit)											
DeMoss Petrie Gas Unit 1											
	Unit 1	33,600,103	75	100.00%	1,515,000	30,906,993	1,515,000	2.00%	2017	1,706,136	5.5%
	Common										
Total DeMoss Petrie G		**33,600,103**	**75**		**1,515,000**	**30,906,993**	**1,515,000**			**1,706,136**	**5.5%**
Gila River											
	Unit 3	222,487,099	550	75.00%	8,879,744	203,626,081	8,879,744	2.00%	2017	10,000,034	4.9%
	Common	30,163,718		75.00%	1,210,874	27,608,233	1,210,874	2.00%	2017	1,363,641	4.9%
Total Gila River		**252,650,817**	**550**		**10,090,618**	**231,234,314**	**10,090,618**			**11,363,674**	**4.9%**
Luna											
	Unit 1	52,657,222	555	33.33%	4,484,719	47,829,964	4,484,719	2.00%	2017	5,050,522	10.6%
	Common										
Total Luna		**52,657,222**	**555**		**4,484,719**	**47,829,964**	**4,484,719**			**5,050,522**	**10.6%**
North Loop Gas											
	Unit 1	5,769,210	25	100.00%	0	5,505,602	563,684	2.00%	2017	634,800	11.5%
	Unit 2	4,332,701	25	100.00%	0	4,132,064	563,684	2.00%	2017	634,800	15.4%
	Unit 3	4,808,026	25	100.00%	0	4,586,666	563,684	2.00%	2017	634,800	13.8%
	Unit 4	15,720,258	20	100.00%	0	14,459,721	450,947	2.00%	2017	507,840	3.5%

Tucson Electric Power Company
Dismantlement Costs for Plants

Account	Description	12/31/14 Investment	Capacity (MW)	Ownership Share	Share of Distmantlement Cost	Estimated Final Retirement Amount	Distributed Distmantlement Cost	Inflation Rate	Effective Rate Year	Inflated Distmantlement Cost	Accrual Rate
	Common				0		0			0	0.0%
Total North Loop Gas		**30,630,195**	**95**	**100.00%**	**2,142,000**	**28,684,053**	**2,142,000**			**2,412,240**	**8.4%**
Sundt Gas											
	Unit 1	5,322,327	25	100.00%	81,185	5,076,480	81,185	2.00%	2017	91,427	1.8%
	Unit 2	5,129,322	25	100.00%	81,185	4,892,953	81,185	2.00%	2017	91,427	1.9%
	Common										
Total Sundt Gas		**10,451,649**	**50**		**162,370**	**9,969,433**	**162,370**			**182,855**	**1.8%**

Statement 8

Tucson Electric Power Company
Current and Proposed Parameters

Account	Description	Current Proj Life AYFR	Current Iowa Curve Shape	Current Avg Life	Current Rem Life	Current Avg Sal	Current Future Net Salvage	TEP Proposed Proj Life AYFR	TEP Proposed Iowa Curve Shape	TEP Proposed Avg Life	TEP Proposed Rem Life	TEP Proposed Avg Sal	TEP Proposed Future Net Salvage	Staff Proposed Proj Life AYFR	Staff Proposed Iowa Curve Shape	Staff Proposed Avg Life	Staff Proposed Rem Life	Staff Proposed Avg Sal	Staff Proposed Future Net Salvage
STEAM PRODUCTION																			
310.00	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	0	0	43.02	18.80	0.0%	0.0%	0	0	43.02	18.80	0.0%	0.0%
311.00	Structures and Improvements	0	0	0.00	0.00	0.0%	0.0%	0	0	35.83	20.41	-16.7%	-19.5%	0	0	35.83	20.41	-11.9%	-13.9%
312.00	Boiler Plant Equipment	0	0	0.00	0.00	0.0%	0.0%	0	0	39.35	23.05	-16.4%	-18.2%	0	0	39.35	23.05	-10.3%	-11.2%
314.00	Turbogenerator Units	0	0	0.00	0.00	0.0%	0.0%	0	0	37.19	23.25	-13.4%	-15.4%	0	0	37.19	23.25	-9.5%	-10.8%
315.00	Accessory Electric Equipment	0	0	0.00	0.00	0.0%	0.0%	0	0	35.88	21.47	-18.6%	-19.4%	0	0	35.88	21.47	-12.8%	-13.4%
316.00	Miscellaneous Power Plant Equipment	0	0	0.00	0.00	0.0%	0.0%	0	0	34.83	20.88	-10.9%	-12.1%	0	0	34.83	20.88	-7.6%	-8.4%
Total Steam Production Plant				0.00	0.00	0.0%	0.0%			38.17	22.58	-15.9%	-17.8%			38.47	22.80	-10.5%	-11.5%
OTHER PRODUCTION																			
Non-Solar																			
341.00	Structures and Improvements	0	0	0.00	0.00	0.0%	0.0%	0	0	41.75	32.67	-14.3%	-14.5%	0	0	41.75	32.67	-7.6%	-7.7%
342.00	Fuel Holders, Products and Accessories	0	0	0.00	0.00	0.0%	0.0%	0	0	40.63	31.82	-14.0%	-14.0%	0	0	40.63	31.82	-7.3%	-7.3%
343.00	Prime Movers	0	0	0.00	0.00	0.0%	0.0%	0	0	40.57	31.72	-8.8%	-8.9%	0	0	40.57	31.72	-4.8%	-4.9%
344.00	Generators and Devices	0	0	0.00	0.00	0.0%	0.0%	0	0	42.10	28.01	-8.5%	-9.3%	0	0	42.10	28.01	-5.1%	-5.5%
345.00	Accessory Electric Equipment	0	0	0.00	0.00	0.0%	0.0%	0	0	39.56	26.72	-7.6%	-8.6%	0	0	39.56	26.72	-4.7%	-5.3%
346.00	Miscellaneous Power Plant Equipment	0	0	0.00	0.00	0.0%	0.0%	0	0	42.19	32.46	-13.6%	-13.7%	0	0	42.19	32.46	-7.2%	-7.3%
Total Non-Solar		0	0	0.00	0.00	0.0%	0.0%	0	0	41.08	30.62	-9.5%	-9.8%			41.56	31.17	-5.3%	-5.5%
Solar																			
344.00	Generators and Devices	0	0	0.00	0.00	0.0%	0.0%	0	0	28.00	24.49	-5.0%	-5.0%	0	0	28.00	24.49	-5.0%	-5.0%
Total Solar		0	0	0.00	0.00	0.0%	0.0%	0	0	28.00	24.49	-5.0%	-5.0%			28.00	24.49	-5.0%	-5.0%
Total Other Production Plant		0	0	0.00	0.00	0.0%	0.0%	0	0	35.89	28.19	-8.1%	-8.3%			36.14	28.50	-5.2%	-5.3%
DISTRIBUTION PLANT																			
360.RW	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	60	R5	60.00	37.36	0.0%	0.0%	60	R5	60.00	37.36	0.0%	0.0%
361.00	Structures and Improvements	55	R1	55.46	47.86	0.0%	0.0%	55	R1	55.54	46.15	0.0%	0.0%	55	R1	55.54	46.15	0.0%	0.0%
362.00	Station Equipment	60	R2.5	59.84	45.73	0.0%	0.0%	55	R2	55.17	41.72	0.0%	0.0%	55	R2	55.17	41.72	0.0%	0.0%
364.00	Poles, Towers and Fixtures	50	R2.5	50.44	35.24	0.0%	0.0%	55	R2.5	55.24	41.84	0.0%	0.0%	55	R2.5	55.24	41.84	0.0%	0.0%
365.00	Overhead Conductors and Devices	55	R3	54.84	39.69	0.0%	0.0%	55	R4	54.61	38.78	0.0%	0.0%	55	R4	54.61	38.78	0.0%	0.0%
366.00	Underground Conduit	65	R4	64.79	45.02	0.0%	0.0%	65	R4	64.76	44.16	0.0%	0.0%	65	R4	64.76	44.16	0.0%	0.0%
367.00	Underground Conductors and Devices	47	R4	46.86	32.68	0.0%	0.0%	50	R4	49.83	34.36	0.0%	0.0%	50	R4	49.83	34.36	0.0%	0.0%
368.OH	Line Transformers - Overhead	45	R2.5	45.48	29.84	0.0%	0.0%	50	R1.5	50.73	35.22	0.0%	0.0%	50	R1.5	50.73	35.22	0.0%	0.0%
368.UG	Line Transformers - Underground	42	S2	42.05	29.51	0.0%	0.0%	45	R2.5	45.18	31.45	0.0%	0.0%	45	R2.5	45.18	31.45	0.0%	0.0%

Tucson Electric Power Company
Current and Proposed Parameters

Account	Description	Current Proj Life AYFR	Current Iowa Curve Shape	Current Avg Life	Current Rem Life	Current Avg Sal	Current Future Net Salvage	TEP Proposed Proj Life AYFR	TEP Proposed Iowa Curve Shape	TEP Proposed Avg Life	TEP Proposed Rem Life	TEP Proposed Avg Sal	TEP Proposed Future Net Salvage	Staff Proposed Proj Life AYFR	Staff Proposed Iowa Curve Shape	Staff Proposed Avg Life	Staff Proposed Rem Life	Staff Proposed Avg Sal	Staff Proposed Future Net Salvage
369.OH	Services - Overhead	45	S3	44.69	27.66	0.0%	0.0%	47	S3	46.63	29.69	0.0%	0.0%	47	S3	46.63	29.69	0.0%	0.0%
369.UG	Services - Underground	60	S3	60.04	45.69	0.0%	0.0%	60	S3	60.05	44.81	0.0%	0.0%	60	S3	60.05	44.81	0.0%	0.0%
370.00	Meters	27	L1	27.43	20.37	0.0%	0.0%	20	L0.5	20.39	16.46	0.0%	0.0%	20	L0.5	20.39	16.46	0.0%	0.0%
373.00	Street Lighting and Signal Systems	50	R3	49.40	34.26	0.0%	0.0%	50	R3	49.38	32.64	0.0%	0.0%	50	R3	49.38	32.64	0.0%	0.0%
Total Distribution Plant		0	0	0.00	0.00	0.0%	0.0%	0	0	50.03	36.00	0.0%	0.0%			50.03	36.00	0.0%	0.0%
GENERAL PLANT																			
Depreciable																			
390.00	Structures and Improvements	40	R4	39.94	34.92	-5.7%	-5.0%	40	R3	39.96	33.19	-5.9%	-5.0%	40	R3	39.96	33.19	-5.9%	-5.0%
392.C0	Transportation - Class 0	18	O2	19.87	12.63	14.7%	15.0%	18	O2	20.22	12.25	17.1%	15.0%	18	O2	20.22	12.25	17.1%	15.0%
392.C1	Transportation - Class 1	8	L2	7.92	4.99	14.6%	15.0%	8	L2	8.11	4.41	17.2%	15.0%	8	L2	8.11	4.41	17.2%	15.0%
392.C2	Transportation - Class 2	8	L1.5	8.03	4.98	14.6%	15.0%	8	L1.5	8.15	4.51	17.6%	15.0%	8	L1.5	8.15	4.51	17.6%	15.0%
392.C3	Transportation - Class 3	9	L3	9.07	4.33	14.6%	15.0%	9	L2	9.33	4.29	18.0%	15.0%	9	L2	9.33	4.29	18.0%	15.0%
392.C4	Transportation - Class 4	14	L1.5	13.94	7.99	14.6%	15.0%	14	L1.5	13.79	7.88	18.0%	15.0%	14	L1.5	13.79	7.88	18.0%	15.0%
392.C5	Transportation - Class 5	13	S2	13.38	7.21	14.7%	15.0%	13	S2	13.39	7.18	16.8%	15.0%	13	S2	13.39	7.18	16.8%	15.0%
392.C6	Transportation - Class 6	15	L2	15.00	13.52	15.0%	15.0%	15	L2	15.02	11.50	15.0%	15.0%	15	L2	15.02	11.50	15.0%	15.0%
392.C7	Transportation - Class 7	14	L1.5	14.15	9.74	15.0%	15.0%	14	L1.5	14.50	8.45	15.0%	15.0%	14	L1.5	14.50	8.45	15.0%	15.0%
392.C8	Transportation - Class 8	13	S2	13.18	9.15	15.0%	15.0%	13	S2	13.24	8.12	15.2%	15.0%	13	S2	13.24	8.12	15.2%	15.0%
392.C9	Transportation - Class 9	20	S2	21.00	11.54	15.0%	15.0%	25	L2	25.55	17.56	15.3%	15.0%	25	L2	25.55	17.56	15.3%	15.0%
396.00	Power Operatied Equipment	15	L2	15.22	10.00	3.7%	5.0%	15	L2	15.13	11.85	1.0%	0.0%	15	L2	15.13	11.85	1.0%	0.0%
397.EM	EMS and SCADA Equipment	20	S3	20.01	15.57	0.0%	0.0%	20	S3	20.02	14.15	0.0%	0.0%	20	S3	20.02	14.15	0.0%	0.0%
Total Depreciable		0	0	0.00	0.00	0.0%	0.0%	0	0	24.20	18.60	2.6%	-0.3%			24.20	18.60	2.6%	-0.3%
Amortizable																			
391.00	Furniture and Office Equipment	24	SQ	24.00	17.60	0.0%	0.0%	24	SQ	24.00	16.29	0.0%	0.0%	24	SQ	24.00	16.29	0.0%	0.0%
391.20	Network and Data Equipment	5	SQ	5.00	2.76	0.0%	0.0%	5	SQ	5.00	2.46	0.0%	0.0%	5	SQ	5.00	2.46	0.0%	0.0%
393.00	Stores Equipment	15	SQ	15.00	9.74	0.0%	0.0%	15	SQ	15.00	8.20	0.0%	0.0%	15	SQ	15.00	8.20	0.0%	0.0%
394.00	Tools, Shop and Garage Equipment	17	SQ	17.00	9.39	0.0%	0.0%	17	SQ	17.00	9.99	0.0%	0.0%	17	SQ	17.00	9.99	0.0%	0.0%
395.00	Laboratory Equipment	17	SQ	17.00	9.19	0.0%	0.0%	17	SQ	17.00	9.00	0.0%	0.0%	17	SQ	17.00	9.00	0.0%	0.0%
397.20	Telecommunications Equipment	15	SQ	15.00	9.12	0.0%	0.0%	15	SQ	15.00	9.87	0.0%	0.0%	15	SQ	15.00	9.87	0.0%	0.0%
398.00	Miscellaneous Equipment	20	SQ	20.00	10.60	0.0%	0.0%	20	SQ	20.00	11.65	0.0%	0.0%	20	SQ	20.00	11.65	0.0%	0.0%
Total Amortizable		0	0	0.00	0.00	0.0%	0.0%	0	0	10.98	6.71	0.0%	0.0%			10.98	6.71	0.0%	0.0%
Total General Plant		0	0	0.00	0.00	0.0%	0.0%	0	0	16.44	11.62	1.4%	-0.2%			16.44	11.62	1.4%	-0.2%

Statement 8

Tucson Electric Power Company
Current and Proposed Parameters

Account	Description	Current Proj Life AYFR	Current Iowa Curve Shape	Current Avg Life	Current Rem Life	Current Avg Sal	Current Future Net Salvage	TEP Proposed Proj Life AYFR	TEP Proposed Iowa Curve Shape	TEP Proposed Avg Life	TEP Proposed Rem Life	TEP Proposed Avg Sal	TEP Proposed Future Net Salvage	Staff Proposed Proj Life AYFR	Staff Proposed Iowa Curve Shape	Staff Proposed Avg Life	Staff Proposed Rem Life	Staff Proposed Avg Sal	Staff Proposed Future Net Salvage
SUBTOTAL		0	0	0.00	0.00	0.0%	0.0%	0	0	36.90	24.77	-7.9%	-9.0%			37.05	24.91	-5.2%	-5.8%
NET SALVAGE																			
108.02	Distribution	0	0	48.80	34.76	-14.8%	-15.0%	0	0	50.03	36.00	-14.1%	-15.0%			50.03	36.00	-4.8%	-5.0%
Total Net Salvage		0	0	0.00	0.00	0.0%	0.0%	0	0	50.03	36.00	-14.1%	-9.8%			50.03	36.00	-4.8%	-5.0%
TOTAL UTILITY		0	0	0.00	0.00	0.0%	0.0%	0	0	29.43	27.04	-9.4%	-10.5%			29.53	27.16	-5.1%	-7.5%
STEAM PRODUCTION (by Unit)																			
Four Corners																			
310.00	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
311.00	Structures and Improvements	0	0	31.54	17.56	-7.9%	-8.0%	0	0	28.98	16.15	-6.2%	-6.3%	0	0	28.98	16.15	-4.7%	-4.9%
312.00	Boiler Plant Equipment	0	0	36.50	17.55	-8.4%	-8.0%	0	0	35.84	16.14	-6.8%	-6.3%	0	0	35.84	16.14	-5.5%	-4.8%
314.00	Turbogenerator Units	0	0	30.52	17.47	-7.0%	-7.9%	0	0	31.67	16.14	-5.6%	-6.3%	0	0	31.67	16.14	-4.2%	-4.8%
315.00	Accessory Electric Equipment	0	0	24.13	17.46	-6.4%	-7.9%	0	0	21.71	16.15	-5.4%	-6.3%	0	0	21.71	16.15	-4.1%	-4.8%
316.00	Miscellaneous Power Plant Equipment	0	0	30.17	17.57	-7.5%	-7.8%	0	0	30.04	16.15	-5.8%	-6.1%	0	0	30.04	16.15	-4.4%	-4.6%
Total Four Corners		0	0	0.00	0.00	0.0%	0.0%	0	0	33.83	16.14	-6.5%	-6.3%			33.83	16.14	-5.2%	-4.8%
Four Corners Unit 4																			
310.00	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
311.00	Structures and Improvements	2029	200-SC	30.90	17.10	-7.5%	-7.5%	2031	200-SC	28.98	16.15	-5.8%	-6.0%	2031	200-SC	28.98	16.15	-4.5%	-4.6%
312.00	Boiler Plant Equipment	2029	200-SC	35.85	17.10	-8.8%	-7.5%	2031	200-SC	35.79	16.14	-7.3%	-6.0%	2031	200-SC	35.79	16.14	-6.1%	-4.6%
314.00	Turbogenerator Units	2029	200-SC	28.99	17.10	-6.4%	-7.5%	2031	200-SC	30.68	16.14	-5.1%	-6.0%	2031	200-SC	30.68	16.14	-3.9%	-4.6%
315.00	Accessory Electric Equipment	2029	200-SC	22.43	17.11	-5.6%	-7.5%	2031	200-SC	21.93	16.15	-4.8%	-6.0%	2031	200-SC	21.93	16.15	-3.6%	-4.6%
316.00	Miscellaneous Power Plant Equipment	2029	200-SC	29.57	17.10	-6.9%	-7.3%	2031	200-SC	29.95	16.15	-5.5%	-5.8%	2031	200-SC	29.95	16.15	-4.2%	-4.4%
Total Four Corners Unit 4		0	0	0.00	0.00	0.0%	0.0%	0	0	33.63	16.14	-6.8%	-6.0%			33.63	16.14	-5.5%	-4.6%
Four Corners Unit 5																			
310.00	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
311.00	Structures and Improvements	2030	200-SC	32.23	18.06	-8.5%	-8.5%	2031	200-SC	28.97	16.15	-6.5%	-6.7%	2031	200-SC	28.97	16.15	-4.9%	-5.1%
312.00	Boiler Plant Equipment	2030	200-SC	37.23	18.05	-8.0%	-8.5%	2031	200-SC	35.90	16.14	-6.3%	-6.7%	2031	200-SC	35.90	16.14	-4.8%	-5.1%
314.00	Turbogenerator Units	2030	200-SC	32.97	18.05	-7.9%	-8.5%	2031	200-SC	33.16	16.14	-6.2%	-6.7%	2031	200-SC	33.16	16.14	-4.7%	-5.1%
315.00	Accessory Electric Equipment	2030	200-SC	26.99	18.06	-7.7%	-8.5%	2031	200-SC	21.47	16.15	-6.1%	-6.7%	2031	200-SC	21.47	16.15	-4.7%	-5.1%
316.00	Miscellaneous Power Plant Equipment	2030	200-SC	30.81	18.06	-8.1%	-8.3%	2031	200-SC	30.14	16.15	-6.2%	-6.4%	2031	200-SC	30.14	16.15	-4.7%	-4.9%
Total Four Corners Unit 5		0	0	0.00	0.00	0.0%	0.0%	0	0	34.06	16.14	-6.3%	-6.7%			34.06	16.14	-4.8%	-5.1%

Tucson Electric Power Company
Current and Proposed Parameters

Account	Description	Current						TEP Proposed						Staff Proposed					
		Proj Life AYFR	Iowa Curve Shape	Avg Life	Rem Life	Avg Sal	Future Net Salvage	Proj Life AYFR	Iowa Curve Shape	Avg Life	Rem Life	Avg Sal	Future Net Salvage	Proj Life AYFR	Iowa Curve Shape	Avg Life	Rem Life	Avg Sal	Future Net Salvage
Navajo																			
310.00	Rights-of-Way	0	0	56.14	23.68	-7.0%	-7.0%	0	0	51.25	15.17	-6.0%	-6.0%	0	0	51.25	15.17	-4.7%	-4.7%
311.00	Structures and Improvements	0	0	41.75	23.36	-7.2%	-7.2%	0	0	32.54	13.56	-5.9%	-6.0%	0	0	32.54	13.56	-4.8%	-4.8%
312.00	Boiler Plant Equipment	0	0	39.61	22.84	-6.7%	-7.2%	0	0	28.93	10.66	-5.5%	-5.9%	0	0	28.93	10.66	-4.6%	-4.9%
314.00	Turbogenerator Units	0	0	41.38	22.72	-6.8%	-7.2%	0	0	29.14	10.12	-5.5%	-5.9%	0	0	29.14	10.12	-4.6%	-4.9%
315.00	Accessory Electric Equipment	0	0	37.59	23.16	-7.1%	-7.2%	0	0	23.29	10.77	-5.9%	-5.9%	0	0	23.29	10.77	-4.8%	-4.8%
316.00	Miscellaneous Power Plant Equipment	0	0	40.69	23.43	-7.0%	-6.9%	0	0	29.26	14.34	-5.9%	-5.9%	0	0	29.26	14.34	-4.7%	-4.7%
Total Navajo		0	0	0.00	0.00	0.0%	0.0%	0	0	28.67	11.04	-5.6%	-5.9%			28.67	11.04	-4.6%	-4.9%
Navajo Unit 1																			
310.00	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
311.00	Structures and Improvements	2034	200-SC	52.47	21.81	-7.2%	-7.1%	2019	200-SC	36.65	4.47	-5.0%	-5.0%	2019	200-SC	36.65	4.47	-4.8%	-4.8%
312.00	Boiler Plant Equipment	2034	200-SC	37.97	21.84	-7.0%	-7.1%	2019	200-SC	21.07	4.47	-5.0%	-5.0%	2019	200-SC	21.07	4.47	-4.8%	-4.8%
314.00	Turbogenerator Units	2034	200-SC	39.73	21.84	-6.5%	-7.1%	2019	200-SC	20.90	4.47	-4.6%	-5.0%	2019	200-SC	20.90	4.47	-4.4%	-4.8%
315.00	Accessory Electric Equipment	2034	200-SC	40.48	21.83	-6.7%	-7.1%	2019	200-SC	13.49	4.47	-4.7%	-5.0%	2019	200-SC	13.49	4.47	-4.6%	-4.8%
316.00	Miscellaneous Power Plant Equipment	2034	200-SC	52.74	21.81	-6.7%	-6.8%	2019	200-SC	38.45	4.47	-4.9%	-4.9%	2019	200-SC	38.45	4.47	-4.7%	-4.7%
Total Navajo Unit 1		0	0	0.00	0.00	0.0%	0.0%	0	0	20.83	4.47	-4.9%	-5.0%			20.83	4.47	-4.7%	-4.8%
Navajo Unit 2																			
310.00	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
311.00	Structures and Improvements	2035	200-SC	48.57	22.76	-7.4%	-7.5%	2030	200-SC	39.37	15.18	-6.3%	-6.6%	2030	200-SC	39.37	15.18	-5.0%	-5.2%
312.00	Boiler Plant Equipment	2035	200-SC	41.28	22.77	-6.9%	-7.5%	2030	200-SC	36.22	15.18	-6.0%	-6.6%	2030	200-SC	36.22	15.18	-4.7%	-5.2%
314.00	Turbogenerator Units	2035	200-SC	40.38	22.78	-7.4%	-7.5%	2030	200-SC	35.06	15.18	-6.5%	-6.6%	2030	200-SC	35.06	15.18	-5.1%	-5.2%
315.00	Accessory Electric Equipment	2035	200-SC	40.14	22.78	-7.2%	-7.5%	2030	200-SC	32.96	15.18	-6.3%	-6.6%	2030	200-SC	32.96	15.18	-5.0%	-5.2%
316.00	Miscellaneous Power Plant Equipment	2035	200-SC	50.34	22.75	-7.0%	-7.2%	2030	200-SC	45.75	15.17	-6.3%	-6.4%	2030	200-SC	45.75	15.17	-4.8%	-4.9%
Total Navajo Unit 2		0	0	0.00	0.00	0.0%	0.0%	0	0	35.95	15.18	-6.2%	-6.6%			35.95	15.18	-4.8%	-5.1%
Navajo Unit 3																			
310.00	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
311.00	Structures and Improvements	2036	200-SC	49.65	23.69	-6.9%	-7.0%	2030	200-SC	44.24	15.18	-5.9%	-6.0%	2030	200-SC	44.24	15.18	-4.6%	-4.7%
312.00	Boiler Plant Equipment	2036	200-SC	41.42	23.71	-6.1%	-7.0%	2030	200-SC	35.40	15.18	-5.2%	-6.0%	2030	200-SC	35.40	15.18	-4.0%	-4.7%
314.00	Turbogenerator Units	2036	200-SC	46.13	23.70	-6.4%	-7.0%	2030	200-SC	40.09	15.18	-5.4%	-6.0%	2030	200-SC	40.09	15.18	-4.3%	-4.7%
315.00	Accessory Electric Equipment	2036	200-SC	44.62	23.70	-7.5%	-7.0%	2030	200-SC	38.19	15.18	-6.5%	-6.0%	2030	200-SC	38.19	15.18	-5.1%	-4.7%
316.00	Miscellaneous Power Plant Equipment	2036	200-SC	54.62	23.69	-8.1%	-6.6%	2030	200-SC	46.90	15.18	-7.1%	-5.8%	2030	200-SC	46.90	15.18	-5.5%	-4.5%

Statement B

Tucson Electric Power Company
Current and Proposed Parameters

Account	Description	Current						TEP Proposed						Staff Proposed					
		Proj Life AYFR	Iowa Curve Shape	Avg Life	Rem Life	Avg Sal	Future Net Salvage	Proj Life AYFR	Iowa Curve Shape	Avg Life	Rem Life	Avg Sal	Future Net Salvage	Proj Life AYFR	Iowa Curve Shape	Avg Life	Rem Life	Avg Sal	Future Net Salvage
Total Navajo Unit 3		0	0	0.00	0.00	0.0%	0.0%	0	0	37.09	15.18	-5.4%	-6.0%			37.09	15.18	-4.2%	-4.7%
Navajo Common																			
310.00	Rights-of-Way	2036	200-SC	56.14	23.68	-7.0%	-7.0%	2030	200-SC	51.25	15.17	-6.0%	-6.0%	2030	200-SC	51.25	15.17	-4.7%	-4.7%
311.00	Structures and Improvements	2036	200-SC	35.95	23.72	-7.3%	-7.3%	2030	200-SC	27.94	15.19	-6.0%	-6.2%	2030	200-SC	27.94	15.19	-4.8%	-4.9%
312.00	Boiler Plant Equipment	2036	200-SC	33.84	23.73	-7.6%	-7.3%	2030	200-SC	27.58	15.19	-6.6%	-6.2%	2030	200-SC	27.58	15.19	-5.3%	-4.9%
314.00	Turbogenerator Units	2036	200-SC	25.06	23.75	-7.3%	-7.3%	2030	200-SC	19.12	15.20	-6.1%	-6.2%	2030	200-SC	19.12	15.20	-4.8%	-4.9%
315.00	Accessory Electric Equipment	2036	200-SC	26.57	23.74	-7.0%	-7.3%	2030	200-SC	20.77	15.20	-5.9%	-6.2%	2030	200-SC	20.77	15.20	-4.6%	-4.9%
316.00	Miscellaneous Power Plant Equipment	2036	200-SC	35.23	23.73	-6.9%	-7.0%	2030	200-SC	25.02	15.19	-5.9%	-6.0%	2030	200-SC	25.02	15.19	-4.6%	-4.7%
Total Navajo Common		0	0	0.00	0.00	0.0%	0.0%	0	0	26.13	15.19	-6.1%	-6.2%			26.13	15.19	-4.9%	-4.8%
San Juan																			
310.00	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
311.00	Structures and Improvements	0	0	43.50	22.50	-9.7%	-9.6%	0	0	28.84	12.30	-9.0%	-9.6%	0	0	28.84	12.30	-7.4%	-7.9%
312.00	Boiler Plant Equipment	0	0	33.25	22.30	-14.3%	-15.1%	0	0	25.11	12.30	-11.6%	-11.7%	0	0	25.11	12.30	-9.9%	-9.7%
314.00	Turbogenerator Units	0	0	35.64	22.18	-8.9%	-9.6%	0	0	28.61	12.30	-9.0%	-9.7%	0	0	28.61	12.30	-7.4%	-8.0%
315.00	Accessory Electric Equipment	0	0	37.69	22.02	-9.3%	-9.5%	0	0	25.55	12.30	-9.1%	-9.7%	0	0	25.55	12.30	-7.5%	-8.0%
316.00	Miscellaneous Power Plant Equipment	0	0	47.93	21.62	-8.7%	-9.1%	0	0	26.25	12.30	-8.1%	-9.3%	0	0	26.25	12.30	-6.7%	-7.6%
Total San Juan		0	0	0.00	0.00	0.0%	0.0%	0	0	25.98	12.30	-10.8%	-11.1%			25.98	12.30	-9.1%	-9.1%
San Juan Unit 1																			
310.00	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
311.00	Structures and Improvements	2036	200-SC	43.21	23.71	-9.4%	-9.9%	2027	200-SC	29.28	12.30	-9.1%	-9.7%	2027	200-SC	29.28	12.30	-7.5%	-8.0%
312.00	Boiler Plant Equipment	2036	200-SC	35.47	23.72	-10.2%	-9.9%	2027	200-SC	25.40	12.30	-10.0%	-9.7%	2027	200-SC	25.40	12.30	-8.6%	-8.0%
314.00	Turbogenerator Units	2036	200-SC	38.79	23.72	-9.2%	-9.9%	2027	200-SC	28.61	12.30	-9.0%	-9.7%	2027	200-SC	28.61	12.30	-7.4%	-8.0%
315.00	Accessory Electric Equipment	2036	200-SC	38.47	23.72	-9.4%	-9.9%	2027	200-SC	25.55	12.30	-9.1%	-9.7%	2027	200-SC	25.55	12.30	-7.5%	-8.0%
316.00	Miscellaneous Power Plant Equipment	2036	200-SC	45.09	23.70	-8.5%	-9.6%	2027	200-SC	26.97	12.30	-8.3%	-9.5%	2027	200-SC	26.97	12.30	-6.8%	-7.8%
Total San Juan Unit 1		0	0	0.00	0.00	0.0%	0.0%	0	0	26.25	12.30	-9.7%	-9.7%			26.25	12.30	-8.2%	-8.0%
San Juan Common																			
310.00	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
311.00	Structures and Improvements	0	0	43.50	22.50	-9.7%	-9.6%	2027	200-SC	12.79	12.30	-0.2%	-0.2%	2027	200-SC	12.79	12.30	-0.2%	-0.2%
312.00	Boiler Plant Equipment	2036	200-SC	33.17	23.73	-247.3%	-263.1%	2027	200-SC	20.75	12.30	-44.1%	-49.0%	2027	200-SC	20.75	12.30	-35.8%	-40.3%
314.00	Turbogenerator Units	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
315.00	Accessory Electric Equipment	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%

Tucson Electric Power Company
Current and Proposed Parameters

Account	Description	Current						TEP Proposed						Staff Proposed					
		Proj Life AYFR	Iowa Curve Shape	Avg Life	Rem Life	Avg Sal	Future Net Salvage	Proj Life AYFR	Iowa Curve Shape	Avg Life	Rem Life	Avg Sal	Future Net Salvage	Proj Life AYFR	Iowa Curve Shape	Avg Life	Rem Life	Avg Sal	Future Net Salvage
316.00	Miscellaneous Power Plant Equipment	0	0	47.93	21.62	-8.7%	-9.1%	2027	200-SC	12.79	12.30	0.0%	0.0%	2027	200-SC	12.79	12.30	0.0%	0.0%
Total San Juan Common		0	0	0.00	0.00	0.0%	0.0%	0	0	20.41	12.30	-43.0%	-47.7%			20.41	12.30	-34.9%	-39.2%
Springerville																			
310.00	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	0	0	43.00	18.81	0.0%	0.0%	0	0	43.00	18.81	0.0%	0.0%
311.00	Structures and Improvements	0	0	0.00	0.00	0.0%	0.0%	0	0	37.20	22.18	-14.5%	-17.8%	0	0	37.20	22.18	-10.6%	-13.0%
312.00	Boiler Plant Equipment	0	0	0.00	0.00	0.0%	0.0%	0	0	48.69	31.72	-16.0%	-18.3%	0	0	48.69	31.72	-9.0%	-10.0%
314.00	Turbogenerator Units	0	0	0.00	0.00	0.0%	0.0%	0	0	45.66	32.41	-6.1%	-6.6%	0	0	45.66	32.41	-3.9%	-3.8%
315.00	Accessory Electric Equipment	0	0	0.00	0.00	0.0%	0.0%	0	0	53.00	30.58	-8.5%	-8.8%	0	0	53.00	30.58	-5.3%	-5.5%
316.00	Miscellaneous Power Plant Equipment	0	0	0.00	0.00	0.0%	0.0%	0	0	44.94	29.44	-8.1%	-9.3%	0	0	44.94	29.44	-5.0%	-5.8%
Total Springerville		0	0	0.00	0.00	0.0%	0.0%	0	0	46.44	30.06	-13.4%	-15.4%			46.44	30.06	-8.0%	-8.9%
Springerville Unit 1																			
310.00	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
311.00	Structures and Improvements	2021	200-SC	11.16	9.39	-0.1%	-0.1%	2045	200-SC	46.47	29.28	-4.2%	-5.5%	2045	200-SC	46.47	29.28	-2.5%	-3.3%
312.00	Boiler Plant Equipment	2021	200-SC	12.80	9.39	-0.3%	-0.1%	2045	200-SC	48.19	29.27	-4.2%	-5.5%	2045	200-SC	48.19	29.27	-2.5%	-3.3%
314.00	Turbogenerator Units	2021	200-SC	13.20	9.39	0.4%	-0.1%	2045	200-SC	48.45	29.27	-4.2%	-5.5%	2045	200-SC	48.45	29.27	-2.5%	-3.3%
315.00	Accessory Electric Equipment	2021	200-SC	12.87	9.39	-0.1%	-0.1%	2045	200-SC	54.33	29.25	-5.1%	-5.5%	2045	200-SC	54.33	29.25	-3.1%	-3.3%
316.00	Miscellaneous Power Plant Equipment	2021	200-SC	10.62	9.39	0.0%	0.0%	2045	200-SC	44.88	29.28	-3.5%	-5.1%	2045	200-SC	44.88	29.28	-2.0%	-2.9%
Total Springerville Unit 1		0	0	0.00	0.00	0.0%	0.0%	0	0	48.48	29.27	-4.2%	-5.5%			48.48	29.27	-2.5%	-3.3%
Springerville Unit 1 Common																			
310.00	Rights-of-Way	2021	200-SC	28.42	9.38	0.0%	0.0%	2045	200-SC	49.87	29.27	0.0%	0.0%	2045	200-SC	49.87	29.27	0.0%	0.0%
311.00	Structures and Improvements	2021	200-SC	17.98	9.38	-0.1%	-0.1%	2045	200-SC	49.61	29.27	-11.8%	-16.8%	2045	200-SC	49.61	29.27	-6.9%	-9.8%
312.00	Boiler Plant Equipment	2021	200-SC	15.67	9.39	-0.1%	-0.1%	2045	200-SC	50.76	29.27	-12.9%	-16.8%	2045	200-SC	50.76	29.27	-7.5%	-9.8%
314.00	Turbogenerator Units	2021	200-SC	20.92	9.38	-0.1%	-0.1%	2045	200-SC	52.60	29.26	-13.7%	-16.8%	2045	200-SC	52.60	29.26	-8.0%	-9.8%
315.00	Accessory Electric Equipment	2021	200-SC	15.50	9.39	-0.1%	-0.1%	2045	200-SC	56.09	29.25	-16.5%	-16.8%	2045	200-SC	56.09	29.25	-9.7%	-9.8%
316.00	Miscellaneous Power Plant Equipment	2021	200-SC	16.57	9.39	0.0%	0.0%	2045	200-SC	55.40	29.25	-15.0%	-16.4%	2045	200-SC	55.40	29.25	-8.6%	-9.4%
Total Springerville Unit 1 Common		0	0	0.00	0.00	0.0%	0.0%	0	0	50.69	29.27	-12.2%	-16.6%			50.69	29.27	-7.1%	-9.7%
Springerville Unit 2																			
310.00	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
311.00	Structures and Improvements	2050	200-SC	50.98	36.57	-8.1%	-7.6%	2050	200-SC	46.76	33.86	-7.0%	-6.7%	2050	200-SC	46.76	33.86	-4.1%	-3.7%
312.00	Boiler Plant Equipment	2050	200-SC	50.50	36.57	-7.3%	-7.6%	2050	200-SC	47.64	33.86	-7.2%	-6.7%	2050	200-SC	47.64	33.86	-4.7%	-3.7%
314.00	Turbogenerator Units	2050	200-SC	51.50	36.56	-8.0%	-7.6%	2050	200-SC	44.78	33.87	-6.7%	-6.7%	2050	200-SC	44.78	33.87	-4.3%	-3.7%

Statement 8

Tucson Electric Power Company
Current and Proposed Parameters

Account	Description	Current Proj Life AYFR	Current Iowa Curve	Current Avg Life	Current Rem Life	Current Avg Sal	Current Future Net Salvage	TEP Proposed Proj Life AYFR	TEP Proposed Iowa Curve	TEP Proposed Avg Life	TEP Proposed Rem Life	TEP Proposed Avg Sal	TEP Proposed Future Net Salvage	Staff Proposed Proj Life AYFR	Staff Proposed Iowa Curve	Staff Proposed Avg Life	Staff Proposed Rem Life	Staff Proposed Avg Sal	Staff Proposed Future Net Salvage
315.00	Accessory Electric Equipment	2050	200-SC	55.14	36.55	-7.5%	-7.6%	2050	200-SC	53.98	33.83	-6.6%	-6.7%	2050	200-SC	53.98	33.83	-3.7%	-3.7%
316.00	Miscellaneous Power Plant Equipment	2050	200-SC	54.63	36.55	-6.8%	-7.1%	2050	200-SC	47.18	33.86	-6.1%	-6.3%	2050	200-SC	47.18	33.86	-3.2%	-3.3%
Total Springerville Unit 2		0	0	0.00	0.00	0.0%	0.0%	0	0	47.30	33.86	-7.0%	-6.7%			47.30	33.86	-4.5%	-3.7%
Springerville Unit 2 Common (Leasehold Imp.)																			
310.00	Rights-of-Way	2020	200-SC	29.45	8.40	0.0%	0.0%	2024	200-SC	33.31	9.38	0.0%	0.0%	2024	200-SC	33.31	9.38	0.0%	0.0%
311.00	Structures and Improvements	2020	200-SC	20.67	8.41	-0.1%	-0.1%	2024	200-SC	21.21	9.38	-36.5%	-39.4%	2024	200-SC	21.21	9.38	-31.8%	-34.3%
312.00	Boiler Plant Equipment	2020	200-SC	16.90	8.41	-0.1%	-0.1%	2024	200-SC	16.91	9.39	-32.3%	-39.4%	2024	200-SC	16.91	9.39	-28.1%	-34.3%
314.00	Turbogenerator Units	2020	200-SC	21.89	8.41	-0.1%	-0.1%	2024	200-SC	25.40	9.38	-39.4%	-39.4%	2024	200-SC	25.40	9.38	-34.3%	-34.3%
315.00	Accessory Electric Equipment	2020	200-SC	27.50	8.41	-0.1%	-0.1%	2024	200-SC	31.60	9.38	-39.4%	-39.4%	2024	200-SC	31.60	9.38	-34.3%	-34.3%
316.00	Miscellaneous Power Plant Equipment	2020	200-SC	20.55	8.41	0.0%	0.0%	2024	200-SC	22.26	9.38	-38.6%	-39.3%	2024	200-SC	22.26	9.38	-33.6%	-34.2%
Total Springerville Unit 2 Common		0	0	0.00	0.00	0.0%	0.0%	0	0	21.34	9.38	-34.4%	-37.4%			21.34	9.38	-29.9%	-32.6%
Springerville Coal Handling																			
310.00	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	2050	200-SC	61.72	33.79	0.0%	0.0%	2050	200-SC	61.72	33.79	0.0%	0.0%
311.00	Structures and Improvements	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%						
312.00	Boiler Plant Equipment	2021	200-SC	11.82	9.39	-0.1%	-0.1%	2050	200-SC	56.69	33.82	-57.2%	-59.4%	2050	200-SC	56.69	33.82	-30.0%	-31.1%
314.00	Turbogenerator Units	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%						
315.00	Accessory Electric Equipment	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%						
316.00	Miscellaneous Power Plant Equipment	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%						
Total Springerville Coal Handling		0	0	0.00	0.00	0.0%	0.0%	0	0	56.74	33.82	-56.6%	-58.7%			56.74	33.82	-29.6%	-30.8%
Sundt																			
310.00	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
311.00	Structures and Improvements	0	0	0.00	0.00	0.0%	0.0%	0	0	36.97	22.69	-42.1%	-44.1%	0	0	39.18	24.32	-27.9%	-29.3%
312.00	Boiler Plant Equipment	0	0	0.00	0.00	0.0%	0.0%	0	0	40.57	24.49	-37.6%	-40.5%	0	0	41.98	25.70	-24.8%	-26.8%
314.00	Turbogenerator Units	0	0	0.00	0.00	0.0%	0.0%	0	0	30.66	19.77	-50.0%	-55.3%	0	0	32.40	21.30	-36.0%	-39.8%
315.00	Accessory Electric Equipment	0	0	0.00	0.00	0.0%	0.0%	0	0	28.88	20.34	-45.9%	-49.0%	0	0	31.26	22.27	-32.0%	-34.1%
316.00	Miscellaneous Power Plant Equipment	0	0	0.00	0.00	0.0%	0.0%	0	0	26.85	19.56	-44.8%	-50.9%	0	0	29.07	21.49	-31.7%	-36.0%
Total Sundt		0	0	0.00	0.00	0.0%	0.0%	0	0	35.41	22.31	-42.0%	-45.4%			37.25	23.82	-28.7%	-31.0%
Sundt Unit 1																			
310.00	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
311.00	Structures and Improvements	2018	200-SC	20.01	6.45	-52.6%	-54.4%	2028	200-SC	22.86	13.27	-53.9%	-58.6%	2032	200-SC	27.69	17.11	-43.3%	-47.1%
312.00	Boiler Plant Equipment	2018	200-SC	17.10	6.45	-33.3%	-54.5%	2028	200-SC	26.28	13.26	-49.3%	-58.7%	2032	200-SC	30.54	17.10	-39.7%	-47.2%

Tucson Electric Power Company
Current and Proposed Parameters

Account	Description	Current Proj Life AYFR	Current Iowa Curve Shape	Current Avg Life	Current Rem Life	Current Avg Sal	Current Future Net Salvage	TEP Proposed Proj Life AYFR	TEP Proposed Iowa Curve Shape	TEP Proposed Avg Life	TEP Proposed Rem Life	TEP Proposed Avg Sal	TEP Proposed Future Net Salvage	Staff Proposed Proj Life AYFR	Staff Proposed Iowa Curve Shape	Staff Proposed Avg Life	Staff Proposed Rem Life	Staff Proposed Avg Sal	Staff Proposed Future Net Salvage
314.00	Turbogenerator Units	2018	200-SC	12.09	6.45	-49.7%	-54.5%	2028	200-SC	22.94	13.27	-52.4%	-58.7%	2032	200-SC	27.36	17.11	-42.1%	-47.2%
315.00	Accessory Electric Equipment	2018	200-SC	9.06	6.45	-53.8%	-54.5%	2028	200-SC	17.20	13.27	-54.0%	-58.7%	2032	200-SC	21.21	17.11	-43.9%	-47.7%
316.00	Miscellaneous Power Plant Equipment	2018	200-SC	10.84	6.45	-51.8%	-54.4%	2028	200-SC	18.52	13.27	-55.6%	-58.6%	2032	200-SC	22.67	17.11	-45.1%	-47.5%
Total Sundt Unit 1		0	0	0.00	0.00	0.0%	0.0%	0	0	22.58	13.27	-51.6%	-58.7%			26.96	17.11	-41.6%	-47.3%
Sundt Unit 2																			
310.00	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
311.00	Structures and Improvements	2020	200-SC	19.23	8.41	-62.0%	-64.2%	2030	200-SC	21.69	15.19	-59.2%	-66.3%	2032	200-SC	23.90	17.11	-45.8%	-51.3%
312.00	Boiler Plant Equipment	2020	200-SC	20.39	8.41	-67.2%	-64.2%	2030	200-SC	28.86	15.19	-63.3%	-66.3%	2032	200-SC	31.08	17.10	-48.9%	-51.2%
314.00	Turbogenerator Units	2020	200-SC	20.59	8.41	-60.5%	-64.2%	2030	200-SC	30.70	15.19	-60.6%	-66.2%	2032	200-SC	33.07	17.10	-46.9%	-51.2%
315.00	Accessory Electric Equipment	2020	200-SC	11.91	8.41	-61.5%	-64.3%	2030	200-SC	18.62	15.20	-63.1%	-66.4%	2032	200-SC	20.60	17.11	-49.0%	-51.6%
316.00	Miscellaneous Power Plant Equipment	2020	200-SC	13.45	8.41	-59.4%	-64.2%	2030	200-SC	19.76	15.20	-61.8%	-66.2%	2032	200-SC	21.78	17.11	-48.0%	-51.4%
Total Sundt Unit 2		0	0	0.00	0.00	0.0%	0.0%	0	0	25.66	15.19	-62.1%	-66.3%			27.91	17.11	-48.1%	-51.3%
Sundt Unit 3																			
310.00	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
311.00	Structures and Improvements	2022	200-SC	24.07	10.36	-71.5%	-75.2%	2032	200-SC	26.92	17.11	-67.8%	-75.7%	2032	200-SC	26.92	17.11	-50.4%	-56.3%
312.00	Boiler Plant Equipment	2022	200-SC	30.31	10.35	-76.9%	-75.2%	2032	200-SC	29.45	17.10	-70.8%	-75.7%	2032	200-SC	29.45	17.10	-52.7%	-56.3%
314.00	Turbogenerator Units	2022	200-SC	22.27	10.36	-73.2%	-75.3%	2032	200-SC	27.66	17.11	-68.5%	-75.7%	2032	200-SC	27.66	17.11	-51.0%	-56.3%
315.00	Accessory Electric Equipment	2022	200-SC	19.68	10.36	-67.5%	-75.3%	2032	200-SC	28.42	17.10	-67.1%	-75.7%	2032	200-SC	28.42	17.10	-49.9%	-56.3%
316.00	Miscellaneous Power Plant Equipment	2022	200-SC	15.48	10.36	-64.1%	-75.2%	2032	200-SC	23.16	17.11	-66.6%	-75.5%	2032	200-SC	23.16	17.11	-49.5%	-56.1%
Total Sundt Unit 3		0	0	0.00	0.00	0.0%	0.0%	0	0	28.24	17.11	-68.9%	-75.7%			28.24	17.11	-51.3%	-56.3%
Sundt Unit 4																			
310.00	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
311.00	Structures and Improvements	2048	200-SC	54.34	34.74	-24.5%	-24.6%	2048	200-SC	52.99	32.01	-32.0%	-32.6%	2048	200-SC	52.99	32.01	-17.5%	-17.8%
312.00	Boiler Plant Equipment	2048	200-SC	54.34	34.74	-24.1%	-24.6%	2048	200-SC	54.25	32.00	-30.3%	-32.6%	2048	200-SC	54.25	32.00	-16.5%	-17.8%
314.00	Turbogenerator Units	2048	200-SC	49.18	34.76	-24.7%	-24.6%	2048	200-SC	41.75	32.06	-29.5%	-32.6%	2048	200-SC	41.75	32.06	-16.2%	-17.9%
315.00	Accessory Electric Equipment	2048	200-SC	53.12	34.75	-23.9%	-24.6%	2048	200-SC	47.13	32.04	-31.1%	-32.6%	2048	200-SC	47.13	32.04	-17.1%	-17.9%
316.00	Miscellaneous Power Plant Equipment	2048	200-SC	48.38	34.77	-20.0%	-24.2%	2048	200-SC	44.82	32.05	-26.9%	-32.2%	2048	200-SC	44.82	32.05	-14.5%	-17.4%
Total Sundt Unit 4		0	0	0.00	0.00	0.0%	0.0%	0	0	50.81	32.02	-30.5%	-32.6%			50.81	32.02	-16.7%	-17.8%
Sundt Solar Booster (Areva)																			
310.00	Rights-of-Way	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%

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Tucson Electric Power Company
Current and Proposed Parameters

Account	Description	Current Proj Life AYFR	Current Iowa Curve Shape	Current Avg Life	Current Rem Life	Current Avg Sal	Current Future Net Salvage	TEP Proposed Proj Life AYFR	TEP Proposed Iowa Curve Shape	TEP Proposed Avg Life	TEP Proposed Rem Life	TEP Proposed Avg Sal	TEP Proposed Future Net Salvage	Staff Proposed Proj Life AYFR	Staff Proposed Iowa Curve Shape	Staff Proposed Avg Life	Staff Proposed Rem Life	Staff Proposed Avg Sal	Staff Proposed Future Net Salvage
311.00	Structures and Improvements	30	SQ	30.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
312.00	Boiler Plant Equipment	30	SQ	30.00	0.00	0.0%	0.0%	2048	200-SC	32.56	32.10	-0.4%	-0.4%	2048	200-SC	32.56	32.10	-0.4%	-0.4%
314.00	Turbogenerator Units	30	SQ	30.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
315.00	Accessory Electric Equipment	30	SQ	30.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
316.00	Miscellaneous Power Plant Equipment	30	SQ	30.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
Total Sundt Solar Booster (Areva)		0	0	0.00	0.00	0.0%	0.0%	0	0	32.56	32.10	-0.4%	-0.4%			32.56	32.10	-0.4%	-0.4%
OTHER PRODUCTION (by Unit)																			
DeMoss Petrie Gas Unit 1																			
341.00	Structures and Improvements	2046	200-SC	40.04	32.98	-7.9%	-9.2%	2046	200-SC	36.97	30.24	-7.3%	-9.0%	2046	200-SC	36.97	30.24	-4.1%	-5.1%
342.00	Fuel Holders, Products and Accessories	2046	200-SC	42.61	32.97	-9.2%	-9.2%	2046	200-SC	42.70	30.22	-8.9%	-9.0%	2046	200-SC	42.70	30.22	-5.0%	-5.1%
343.00	Prime Movers	2046	200-SC	34.38	33.01	-9.2%	-9.2%	2046	200-SC	34.41	30.25	-1.3%	-9.0%	2046	200-SC	34.41	30.25	-0.7%	-5.1%
344.00	Generators and Devices	2046	200-SC	42.59	32.97	-9.2%	-9.2%	2046	200-SC	42.56	30.22	-8.7%	-9.0%	2046	200-SC	42.56	30.22	-5.0%	-5.1%
345.00	Accessory Electric Equipment	2046	200-SC	42.54	32.97	-9.2%	-9.2%	2046	200-SC	41.80	30.22	-3.4%	-9.0%	2046	200-SC	41.80	30.22	-1.9%	-5.1%
346.00	Miscellaneous Power Plant Equipment	2046	200-SC	41.25	32.98	-9.2%	-9.2%	2046	200-SC	40.73	30.22	-8.9%	-9.0%	2046	200-SC	40.73	30.22	-5.1%	-5.1%
Total DeMoss Petrie Gas Unit 1		0	0	0.00	0.00	0.0%	0.0%	0	0	42.35	30.22	-8.3%	-9.0%			42.35	30.22	-4.7%	-5.1%
Gila River																			
341.00	Structures and Improvements	0	0	0.00	0.00	0.0%	0.0%	0	0	42.18	32.06	-8.4%	-8.4%	0	0	42.18	32.06	-4.5%	-4.5%
342.00	Fuel Holders, Products and Accessories	0	0	0.00	0.00	0.0%	0.0%	0	0	42.49	32.06	-8.4%	-8.4%	0	0	42.49	32.06	-4.5%	-4.5%
343.00	Prime Movers	0	0	0.00	0.00	0.0%	0.0%	0	0	41.47	32.06	-8.3%	-8.3%	0	0	41.47	32.06	-4.5%	-4.5%
344.00	Generators and Devices	0	0	0.00	0.00	0.0%	0.0%	0	0	42.63	32.06	-8.3%	-8.3%	0	0	42.63	32.06	-4.5%	-4.5%
345.00	Accessory Electric Equipment	0	0	0.00	0.00	0.0%	0.0%	0	0	42.38	32.06	-8.3%	-8.3%	0	0	42.38	32.06	-4.5%	-4.5%
346.00	Miscellaneous Power Plant Equipment	0	0	0.00	0.00	0.0%	0.0%	0	0	42.28	32.06	-8.4%	-8.4%	0	0	42.28	32.06	-4.5%	-4.5%
Total Gila River		0	0	0.00	0.00	0.0%	0.0%	0	0	41.72	32.06	-8.3%	-8.3%			41.72	32.06	-4.5%	-4.5%
Gila River Unit 3																			
341.00	Structures and Improvements	45	SQ	45.00	0.00	0.0%	0.0%	2048	200-SC	42.38	32.06	-8.3%	-8.3%	2048	200-SC	42.38	32.06	-4.5%	-4.5%
342.00	Fuel Holders, Products and Accessories	45	SQ	45.00	0.00	0.0%	0.0%	2048	200-SC	41.24	32.06	-8.3%	-8.3%	2048	200-SC	41.24	32.06	-4.5%	-4.5%
343.00	Prime Movers	45	SQ	45.00	0.00	0.0%	0.0%	2048	200-SC	41.57	32.06	-8.3%	-8.3%	2048	200-SC	41.57	32.06	-4.5%	-4.5%
344.00	Generators and Devices	45	SQ	45.00	0.00	0.0%	0.0%	2048	200-SC	42.63	32.06	-8.3%	-8.3%	2048	200-SC	42.63	32.06	-4.5%	-4.5%
345.00	Accessory Electric Equipment	45	SQ	45.00	0.00	0.0%	0.0%	2048	200-SC	42.38	32.06	-8.3%	-8.3%	2048	200-SC	42.38	32.06	-4.5%	-4.5%
346.00	Miscellaneous Power Plant Equipment	45	SQ	45.00	0.00	0.0%	0.0%	2048	200-SC	41.89	32.06	-8.3%	-8.3%	2048	200-SC	41.89	32.06	-4.5%	-4.5%
Total Gila River Unit 3		0	0	0.00	0.00	0.0%	0.0%	0	0	41.75	32.06	-8.3%	-8.3%			41.75	32.06	-4.5%	-4.5%

Tucson Electric Power Company
Current and Proposed Parameters

Account	Description	Current						TEP Proposed						Staff Proposed					
		Proj Life AYFR	Iowa Curve Shape	Avg Life	Rem Life	Avg Sal	Future Net Salvage	Proj Life AYFR	Iowa Curve Shape	Avg Life	Rem Life	Avg Sal	Future Net Salvage	Proj Life AYFR	Iowa Curve Shape	Avg Life	Rem Life	Avg Sal	Future Net Salvage
Gila River Common																			
341.00	Structures and Improvements	45	SQ	45.00	0.00	0.0%	0.0%	2048	200-SC	42.15	32.06	-8.4%	-8.4%	2048	200-SC	42.15	32.06	-4.5%	-4.5%
342.00	Fuel Holders, Products and Accessories	45	SQ	45.00	0.00	0.0%	0.0%	2048	200-SC	42.52	32.06	-8.4%	-8.4%	2048	200-SC	42.52	32.06	-4.5%	-4.5%
343.00	Prime Movers	45	SQ	45.00	0.00	0.0%	0.0%	2048	200-SC	39.05	32.07	-8.4%	-8.4%	2048	200-SC	39.05	32.07	-4.5%	-4.5%
344.00	Generators and Devices	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
345.00	Accessory Electric Equipment	45	SQ	45.00	0.00	0.0%	0.0%	2048	200-SC	42.39	32.06	-8.4%	-8.4%	2048	200-SC	42.39	32.06	-4.5%	-4.5%
346.00	Miscellaneous Power Plant Equipment	45	SQ	45.00	0.00	0.0%	0.0%	2048	200-SC	42.29	32.06	-8.4%	-8.4%	2048	200-SC	42.29	32.06	-4.5%	-4.5%
Total Gila River Common		0	0	0.00	0.00	0.0%	0.0%	0	0	41.49	32.06	-8.4%	-8.4%			41.49	32.06	-4.5%	-4.5%
Luna																			
341.00	Structures and Improvements	2051	200-SC	42.47	37.52	-19.5%	-19.6%	2051	200-SC	42.38	34.80	-18.7%	-18.8%	2051	200-SC	42.38	34.80	-9.6%	-9.6%
342.00	Fuel Holders, Products and Accessories	2051	200-SC	42.51	37.52	-19.6%	-19.6%	2051	200-SC	42.56	34.80	-18.8%	-18.8%	2051	200-SC	42.56	34.80	-9.6%	-9.6%
343.00	Prime Movers	2051	200-SC	39.20	37.54	-16.3%	-19.7%	2051	200-SC	37.40	34.82	-15.5%	-18.8%	2051	200-SC	37.40	34.82	-7.9%	-9.6%
344.00	Generators and Devices	2051	200-SC	41.74	37.52	-14.5%	-19.6%	2051	200-SC	40.73	34.80	-11.1%	-18.8%	2051	200-SC	40.73	34.80	-5.7%	-9.6%
345.00	Accessory Electric Equipment	40	0	40.00	0.00	0.0%	0.0%	2051	200-SC	35.29	34.83	-18.8%	-18.8%	2051	200-SC	35.29	34.83	-9.6%	-9.6%
346.00	Miscellaneous Power Plant Equipment	2051	200-SC	42.48	37.52	-19.6%	-19.6%	2051	200-SC	42.48	34.80	-18.7%	-18.8%	2051	200-SC	42.48	34.80	-9.6%	-9.6%
Total Luna		0	0	0.00	0.00	0.0%	0.0%	0	0	40.97	34.80	-16.0%	-18.8%			40.97	34.80	-8.2%	-9.6%
North Loop Gas																			
341.00	Structures and Improvements	0	0	24.42	7.02	-11.2%	-12.1%	0	0	34.58	13.74	-13.4%	-14.2%	0	0	39.55	18.30	-10.7%	-11.5%
342.00	Fuel Holders, Products and Accessories	0	0	43.49	33.88	-5.9%	-5.9%	0	0	42.70	30.22	-5.7%	-5.7%	0	0	42.70	30.22	-3.2%	-3.2%
343.00	Prime Movers	0	0	8.36	5.46	-12.5%	-12.5%	0	0	15.51	12.30	-12.4%	-15.4%	0	0	20.42	17.11	-10.1%	-12.7%
344.00	Generators and Devices	0	0	36.87	19.70	-8.5%	-8.9%	0	0	42.21	22.77	-9.3%	-9.8%	0	0	44.18	25.12	-6.9%	-7.2%
345.00	Accessory Electric Equipment	0	0	27.62	12.41	-9.3%	-10.3%	0	0	33.62	17.60	-10.7%	-11.9%	0	0	37.70	21.46	-8.3%	-9.2%
346.00	Miscellaneous Power Plant Equipment	0	0	27.71	8.02	-10.4%	-11.7%	0	0	38.64	14.59	-12.2%	-13.7%	0	0	43.21	18.97	-9.8%	-11.0%
Total North Loop Gas		0	0	0.00	0.00	0.0%	0.0%	0	0	37.09	20.31	-9.8%	-10.5%			40.46	23.50	-7.4%	-7.9%
North Loop Gas Unit 1																			
341.00	Structures and Improvements	2017	200-SC	19.02	5.46	-11.1%	-11.1%	2027	200-SC	29.10	12.30	-13.4%	-13.4%	2032	200-SC	34.34	17.10	-11.0%	-11.0%
342.00	Fuel Holders, Products and Accessories	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
343.00	Prime Movers	2017	200-SC	9.86	5.46	-11.1%	-11.1%	2027	200-SC	19.70	12.30	-13.3%	-13.4%	2032	200-SC	24.49	17.11	-10.9%	-11.0%
344.00	Generators and Devices	2017	200-SC	27.57	5.46	-11.0%	-11.1%	2027	200-SC	38.80	12.29	-13.1%	-13.4%	2032	200-SC	43.83	17.09	-10.9%	-11.0%
345.00	Accessory Electric Equipment	2017	200-SC	20.04	5.46	-10.9%	-11.1%	2027	200-SC	28.69	12.30	-13.1%	-13.4%	2032	200-SC	33.98	17.10	-10.8%	-11.0%
346.00	Miscellaneous Power Plant Equipment	2017	200-SC	19.46	5.46	-11.1%	-11.1%	2027	200-SC	30.66	12.30	-13.4%	-13.4%	2032	200-SC	35.81	17.10	-11.0%	-11.0%
Total North Loop Gas Unit 1		0	0	0.00	0.00	0.0%	0.0%	0	0	32.33	12.29	-13.1%	-13.4%			37.65	17.09	-10.9%	-11.0%

Tucson Electric Power Company
Current and Proposed Parameters

Account	Description	Current						TEP Proposed						Staff Proposed					
		Proj Life AYFR	Iowa Curve Shape	Avg Life	Rem Life	Avg Sal	Future Net Salvage	Proj Life AYFR	Iowa Curve Shape	Avg Life	Rem Life	Avg Sal	Future Net Salvage	Proj Life AYFR	Iowa Curve Shape	Avg Life	Rem Life	Avg Sal	Future Net Salvage
North Loop Gas Unit 2																			
341.00	Structures and Improvements	2017	200-SC	30.61	5.46	-15.5%	-15.5%	2027	200-SC	41.27	12.29	-17.9%	-17.9%	2032	200-SC	46.54	17.08	-14.6%	-14.6%
342.00	Fuel Holders, Products and Accessories	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
343.00	Prime Movers	2017	200-SC	15.82	5.46	-15.5%	-15.5%	2027	200-SC	8.23	12.31	-7.0%	-17.9%	2032	200-SC	12.12	17.12	-5.7%	-14.7%
344.00	Generators and Devices	2017	200-SC	31.80	5.46	-14.7%	-15.5%	2027	200-SC	43.04	12.29	-16.9%	-17.9%	2032	200-SC	47.97	17.08	-13.8%	-14.6%
345.00	Accessory Electric Equipment	2017	200-SC	25.59	5.46	-15.1%	-15.5%	2027	200-SC	31.85	12.29	-17.3%	-17.9%	2032	200-SC	37.58	17.09	-14.2%	-14.7%
346.00	Miscellaneous Power Plant Equipment	2017	200-SC	44.27	5.46	-15.5%	-15.5%	2027	200-SC	53.34	12.28	-17.8%	-17.8%	2032	200-SC	57.63	17.07	-14.6%	-14.6%
Total North Loop Gas Unit 2		0	0	0.00	0.00	0.0%	0.0%	0	0	33.25	12.29	-15.7%	-17.9%			39.70	17.09	-12.8%	-14.7%
North Loop Gas Unit 3																			
341.00	Structures and Improvements	2017	200-SC	30.61	5.46	-13.3%	-13.3%	2027	200-SC	41.27	12.29	-16.1%	-16.1%	2032	200-SC	46.54	17.08	-13.2%	-13.2%
342.00	Fuel Holders, Products and Accessories	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
343.00	Prime Movers	2017	200-SC	7.31	5.46	-13.3%	-13.3%	2027	200-SC	17.12	12.30	-15.4%	-16.1%	2032	200-SC	21.98	17.11	-12.7%	-13.2%
344.00	Generators and Devices	2017	200-SC	32.28	5.46	-12.0%	-13.3%	2027	200-SC	43.69	12.29	-14.5%	-16.1%	2032	200-SC	48.67	17.08	-11.9%	-13.2%
345.00	Accessory Electric Equipment	2017	200-SC	25.63	5.46	-13.0%	-13.3%	2027	200-SC	31.87	12.29	-15.6%	-16.1%	2032	200-SC	37.60	17.09	-12.8%	-13.2%
346.00	Miscellaneous Power Plant Equipment	2017	200-SC	44.27	5.46	-13.3%	-13.3%	2027	200-SC	53.34	12.28	-16.1%	-16.1%	2032	200-SC	57.63	17.07	-13.2%	-13.2%
Total North Loop Gas Unit 3		0	0	0.00	0.00	0.0%	0.0%	0	0	32.54	12.29	-14.9%	-16.1%			38.37	17.09	-12.2%	-13.2%
North Loop Gas Unit 4																			
341.00	Structures and Improvements	2047	200-SC	42.41	33.89	2.7%	-5.9%	2046	200-SC	41.22	30.22	2.6%	-5.7%	2046	200-SC	41.22	30.22	5.0%	-3.2%
342.00	Fuel Holders, Products and Accessories	2047	200-SC	43.49	33.88	-5.9%	-5.9%	2046	200-SC	42.70	30.22	-5.7%	-5.7%	2046	200-SC	42.70	30.22	-3.2%	-3.2%
343.00	Prime Movers	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%	0	0	0.00	0.00	0.0%	0.0%
344.00	Generators and Devices	2047	200-SC	43.46	33.88	-5.6%	-5.9%	2046	200-SC	42.66	30.22	-5.4%	-5.7%	2046	200-SC	42.66	30.22	-3.0%	-3.2%
345.00	Accessory Electric Equipment	2047	200-SC	42.61	33.89	-4.7%	-5.9%	2046	200-SC	41.29	30.22	-4.5%	-5.7%	2046	200-SC	41.29	30.22	-2.6%	-3.2%
346.00	Miscellaneous Power Plant Equipment	2047	200-SC	43.49	33.88	-3.2%	-5.9%	2046	200-SC	42.70	30.22	-3.1%	-5.7%	2046	200-SC	42.70	30.22	-1.7%	-3.2%
Total North Loop Gas Unit 4		0	0	0.00	0.00	0.0%	0.0%	0	0	42.56	30.22	-5.3%	-5.7%			42.56	30.22	-3.0%	-3.2%
Solar Units (Generators and Devices)																			
344.00	DeMoss Petrie	20	S4	20.00	17.06	0.0%	0.0%	28	S6	28.00	16.15	-5.0%	-5.0%	28	S6	28.00	16.15	-5.0%	-5.0%
344.00	Fort Huachuca	20	S4	20.00	17.06	0.0%	0.0%	28	S6	28.00	27.50	-5.0%	-5.0%	28	S6	28.00	27.50	-5.0%	-5.0%
344.00	HQ Rooftop	20	S4	20.00	17.06	0.0%	0.0%	28	S6	28.00	25.50	-5.0%	-5.0%	28	S6	28.00	25.50	-5.0%	-5.0%
344.00	OH Rooftop	20	S4	20.00	17.06	0.0%	0.0%	28	S6	28.00	24.50	-5.0%	-5.0%	28	S6	28.00	24.50	-5.0%	-5.0%
344.00	OH Test Yard	20	S4	20.00	17.06	0.0%	0.0%	28	S6	28.00	16.83	-5.0%	-5.0%	28	S6	28.00	16.83	-5.0%	-5.0%
344.00	Prairie Fire	20	S4	20.00	17.06	0.0%	0.0%	28	S6	28.00	25.50	-5.0%	-5.0%	28	S6	28.00	25.50	-5.0%	-5.0%

Statement 8

Tucson Electric Power Company
Current and Proposed Parameters

Account	Description	Current						TEP Proposed						Staff Proposed					
		Proj Life AYFR	Iowa Curve Shape	Avg Life	Rem Life	Avg Sal	Future Net Salvage	Proj Life AYFR	Iowa Curve Shape	Avg Life	Rem Life	Avg Sal	Future Net Salvage	Proj Life AYFR	Iowa Curve Shape	Avg Life	Rem Life	Avg Sal	Future Net Salvage
344.00	Springerville Sites 1-3 (Legacy)	20	S4	20.00	17.06	0.0%	0.0%	28	S6	28.00	16.11	-5.0%	-5.0%	28	S6	28.00	16.11	-5.0%	-5.0%
344.00	Springerville Site 4	20	S4	20.00	17.06	0.0%	0.0%	28	S6	28.00	23.50	-5.0%	-5.0%	28	S6	28.00	23.50	-5.0%	-5.0%
343.00	Tucson	20	S4	20.00	17.06	0.0%	0.0%	28	S6	28.00	11.82	-5.0%	-5.0%	28	S6	28.00	11.82	-5.0%	-5.0%
344.00	U of A Tech Park Site 1	20	S4	20.00	17.06	0.0%	0.0%	28	S6	28.00	23.50	-5.0%	-5.0%	28	S6	28.00	23.50	-5.0%	-5.0%
345.00	U of A Tech Park Site 2	20	S4	20.00	17.06	0.0%	0.0%	28	S6	28.00	24.50	-5.0%	-5.0%	28	S6	28.00	24.50	-5.0%	-5.0%
346.00	White Mountain	20	S4	20.00	17.06	0.0%	0.0%	28	S6	28.00	27.50	-5.0%	-5.0%	28	S6	28.00	27.50	-5.0%	-5.0%
Total Solar Units		0	0	0.00	0.00	0.0%	0.0%	0	0	28.00	24.49	-5.0%	-5.0%			28.00	24.49	-5.0%	-5.0%
Sundt Gas																			
341.00	Structures and Improvements	0	0	28.10	5.46	-1.8%	-1.8%	0	0	37.43	12.29	-1.9%	-2.2%	0	0	42.20	17.09	-1.7%	-1.8%
342.00	Fuel Holders, Products and Accessories	0	0	9.71	5.46	-1.8%	-1.8%	0	0	19.39	12.30	-2.2%	-2.2%	0	0	24.25	17.11	-2.0%	-1.8%
343.00	Prime Movers	0	0	15.82	5.46	-1.8%	-1.8%	0	0	25.38	12.30	-2.2%	-2.2%	0	0	30.03	17.10	-2.0%	-1.8%
344.00	Generators and Devices	0	0	30.02	5.46	-1.7%	-1.7%	0	0	39.83	12.29	-2.0%	-2.1%	0	0	44.94	17.09	-1.8%	-1.7%
345.00	Accessory Electric Equipment	0	0	22.40	5.46	-1.7%	-1.8%	0	0	34.86	12.29	-2.1%	-2.2%	0	0	40.34	17.09	-1.9%	-1.8%
346.00	Miscellaneous Power Plant Equipment	0	0	42.42	5.46	-1.8%	-1.8%	0	0	51.58	12.28	-2.2%	-2.2%	0	0	55.91	17.07	-2.0%	-1.8%
Total Sundt Gas		0	0	0.00	0.00	0.0%	0.0%	0	0	36.18	12.29	-2.0%	-2.1%			41.53	17.09	-1.8%	-1.7%
Sundt Gas Unit 1																			
341.00	Structures and Improvements	2017	200-SC	28.10	5.46	-1.7%	-1.7%	2027	200-SC	37.43	12.29	-1.8%	-2.1%	2032	200-SC	42.20	17.09	-1.5%	-1.7%
342.00	Fuel Holders, Products and Accessories	2017	200-SC	9.71	5.46	-1.7%	-1.7%	2027	200-SC	19.39	12.30	-2.1%	-2.1%	2032	200-SC	24.25	17.11	-1.7%	-1.7%
343.00	Prime Movers	2017	200-SC	15.82	5.46	-1.7%	-1.7%	2027	200-SC	25.38	12.30	-2.1%	-2.1%	2032	200-SC	30.03	17.10	-1.7%	-1.7%
344.00	Generators and Devices	2017	200-SC	31.37	5.46	-1.7%	-1.7%	2027	200-SC	40.65	12.29	-2.0%	-2.1%	2032	200-SC	45.79	17.09	-1.6%	-1.7%
345.00	Accessory Electric Equipment	2017	200-SC	23.05	5.46	-1.7%	-1.7%	2027	200-SC	35.64	12.29	-2.0%	-2.1%	2032	200-SC	41.15	17.09	-1.7%	-1.7%
346.00	Miscellaneous Power Plant Equipment	2017	200-SC	42.93	5.46	-1.7%	-1.7%	2027	200-SC	52.10	12.28	-2.1%	-2.1%	2032	200-SC	56.43	17.07	-1.7%	-1.7%
Total Sundt Gas Unit 1		0	0	0.00	0.00	0.0%	0.0%	0	0	36.88	12.29	-2.0%	-2.1%			42.28	17.09	-1.6%	-1.7%
Sundt Gas Unit 2																			
341.00	Structures and Improvements	2017	200-SC	28.10	5.46	-1.8%	-1.8%	2027	200-SC	37.43	12.29	-1.9%	-2.2%	2032	200-SC	42.20	17.09	-1.9%	-2.2%
342.00	Fuel Holders, Products and Accessories	2017	200-SC	9.71	5.46	-1.8%	-1.8%	2027	200-SC	19.39	12.30	-2.2%	-2.2%	2032	200-SC	24.25	17.11	-2.2%	-2.2%
343.00	Prime Movers	2017	200-SC	15.82	5.46	-1.8%	-1.8%	2027	200-SC	25.38	12.30	-2.2%	-2.2%	2032	200-SC	30.03	17.10	-2.2%	-2.2%
344.00	Generators and Devices	2017	200-SC	28.72	5.46	-1.7%	-1.8%	2027	200-SC	38.99	12.29	-1.9%	-2.2%	2032	200-SC	44.06	17.09	-1.9%	-2.2%
345.00	Accessory Electric Equipment	2017	200-SC	21.84	5.46	-1.8%	-1.8%	2027	200-SC	34.18	12.29	-2.1%	-2.2%	2032	200-SC	39.63	17.09	-2.1%	-2.2%
346.00	Miscellaneous Power Plant Equipment	2017	200-SC	42.08	5.46	-1.8%	-1.8%	2027	200-SC	51.24	12.28	-2.2%	-2.2%	2032	200-SC	55.57	17.07	-2.2%	-2.2%
Total Sundt Gas Unit 2		0	0	0.00	0.00	0.0%	0.0%	0	0	35.47	12.29	-2.0%	-2.2%			40.78	17.09	-2.0%	-1.8%

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S FIRST SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 8, 2016

RUCO 1.02

For each account, provide a specific and detailed narrative of the process employed by the Dr. White to arrive at his recommended service lives and net salvage rates. The response should identify each significant and/or meaningful item of information, whether that information is the historical data, management input or other and how such information was specifically combined to arrive at the final recommended level for each account. The response should include current life/salvage, industry averages and recommended values.

RESPONSE:

The process employed by Dr. White to arrive at his recommended service lives and net salvage rates is described in Exhibit REW–1. Dr. White neither observed nor was informed of any significant changes in the composition of plant categories or anticipated changes in future forces of retirement that would measurably impact hazard rates or conditional probabilities of retirement observed in the past. Dr. White does not examine or consider industry averages in formulating his recommendations.

RESPONDENT:

Dr. Ronald White

WITNESS:

Dr. Ronald White

Direct Testimony of Dr. Ronald E. White

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO UNIFORM DATA REQUESTS - 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
November 13, 2015

INTERNAL & EXTERNAL REPORTING:

UDR 1.006

Please provide a copy of the Company's most recent Integrated Resource plans.

RESPONSE:

Please see the most recent Integrated Resource Plan at https://www.tep.com/projects/planning/.

RESPONDENT:

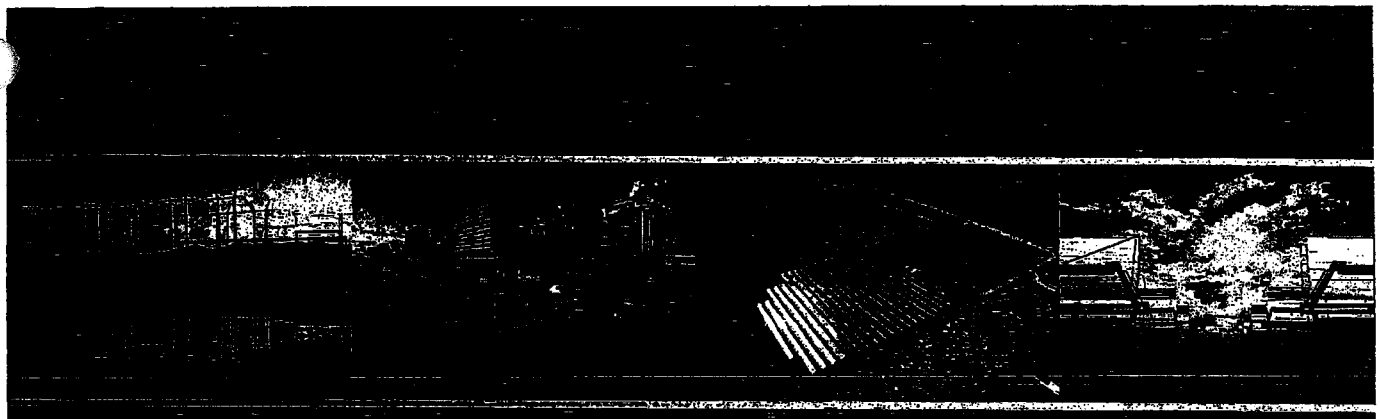
Victor Aguirre

WITNESS:

Michael Sheehan

Arizona Corporation Commission ("Commission")
Fortis Inc. ("Fortis")
Tucson Electric Power Company ("TEP")
UNS Energy Corporation ("UNS")
UNS Energy Corporation and Fortis Inc. Joint Notice of Reorganization Settlement Agreement approved in Decision No. 74689 (August 12, 2014) (the "UNS-Fortis Settlement Agreement")

UniSource Energy Services ("UES")
UniSource Energy Development Company ("UED")
UNS Electric, Inc. ("UNS Electric" or the "Company")
UNS Gas, Inc. ("UNS Gas")
UNS Electric, Inc. 2014 Rate Case Settlement Agreement approved in Decision No. 74689 (August 12, 2014) (the "2014 Settlement Agreement")



Tucson Electric Power

2016 Preliminary Integrated Resource Plan

March 1, 2016

System Resource Capacity

Table 5 shows TEP's preliminary firm resource capacity based on a resource's contribution to system peak.

Table 5 – Capacity Resources, System Peak Demand (MW)

Firm Resource Capacity (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Four Corners	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	
Navajo	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168		
San Juan	340	340	170	170	170	170											
Springerville	598	793	793	793	793	793	793	793	793	793	793	793	793	793	793	793	793
Remote Coal Resources	1216	1411	1241	1241	1241	1241	1071	1071	1071	1071	1071	1071	1071	1071	1071	903	793
Sundt 1-4	422	422	422	422	422	422	422	422	422	422	422	422	422	422	422	422	422
Luna Energy Facility	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185
Gila River Power Station	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374
DeMoss Petrie CT	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
North Loop CT 1-4	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Sundt CT 1-2	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
Total Natural Gas Resources	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200
Utility Scale Renewables	97	110	136	149	176	189	215	228	255	268	301	301	334	334	367	367	367
Demand Response	19	24	29	35	40	45	45	45	45	45	45	45	45	50	50	50	50
Total Renewable & EE Resources	116	134	165	184	216	234	260	273	300	313	346	346	379	384	417	417	417
Short-Term Market Resources	425	275	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Storage Resources	0	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Total Firm Resources	2956	3040	2626	2645	2677	2695	2551	2564	2591	2604	2637	2637	2670	2675	2708	2540	2430

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FOURTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 8, 2016

STF 4.02

RE: Response to STF 2.02: The Excel file provided in response to STF 2.02 includes a tab entitled "Dismantlement". Column Y of that Excel tab includes costs for Steam Production plants.

a. The costs shown indicate a different year for each plant. Please provide the source of the cost amounts shown in Column Y of tab "Dismantlement" of the Excel file provided in response to STF 2.02. Please include a specific cite to where the amount shown in Column Y is shown in the source provided.

b. Please provide a copy of the most recent dismantlement or decommissioning study for each Steam Production Plant shown on tab "Dismantlement" of the Excel file provided in response to STF 2.02.

c. Please provide the source for the Inflation Rate shown in cell U3 of tab "Dismantlement" of the Excel file provided in response to STF 2.02.

RESPONSE:

ONE OF THE FILES LISTED BELOW CONTAINS COMPETITIVELY-SENSITIVE CONFIDENTIAL INFORMATION THAT WILL BE PROVIDED TO THE REQUESTING PARTY PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT AND UPON AUTHORIZATION OF THIRD PARTY OF DOCUMENT TO PROVIDE SUCH DOCUMENT.

SOME OF THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

File Name	Bates Numbers
STF 4.02 BandM 2011 TEP Study.pdf	TEP\019499-019540
STF 4.02 FC 45Shutdown2038Scenario1Q15UpdateSupportSch-Confidential.pdf	TEP\019670-019674
STF 4.02 Navajo Decommissioning Report 2011 Update-Confidential.pdf	TEP\019675-019687
STF 4.02 SJGS 2013 Decom Study-Competitively Sensitive Confidential.pdf	TEP\019837-019979

a. The "Dismantlement" cost as indicated for each respective year was obtained from the decommissioning study performed by an independent engineering firm, who typically issues a final report upon completion of the engineering study. The amount shown in Column Y is shown in the table provided as follows:

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FOURTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 8, 2016

Steam Production Plant	Decommissioning Study Performed by	Year of Report Issued	Cite of Decommissioning Study	Hyperlink to Decommissioning Study Support
Four Corners	Shaw Environmental Inc,. a CB&I Company	March 2015	List of Tables - Table 1	STF 4.02 FC 45Shutdown2038Scenario1Q15UpdateSupportSch-Confidential.pdf
Navajo	Sargent & Lundy	2008 Study; 2011 Update	Page 9 of Sargent & Lundy LLC Demolition Estimate of Entire Station Report	STF 4.02 Navajo Decommissioning Report 2011 Update-Confidential.pdf
San Juan	Black & Veatch / PNM	September 2013	Table 6-4, Table 6-5 & Table 6-6	STF 4.02 SJGS 2013 Decom Study-Competitively Sensitive Confidential.pdf
Springerville	Burns & McDonnell Engineering Company, Inc., Kansas City, Missouri	December 2011	Appendix A, Schedule A-3 - Decommissioning Cost estimates excluding 50% of costs related to Common Facilities	STF 4.02 BandM 2011 TEP Study.pdf
Sundt	Burns & McDonnell Engineering Company, Inc., Kansas City, Missouri	December 2011	Appendix A, Schedule A-1 - Decommissioning Cost estimates	STF 4.02 BandM 2011 TEP Study.pdf

b. A copy of the decommissioning study for each Steam Production Plant can be found in the files listed above response to Part a.

c. TEP takes into consideration of various sources (e.g. Bloomberg, Consumer Price Index) when evaluating the proper inflation rate to be used. For the depreciation study purposes, TEP elected 2% inflation rate which is a reasonable figure closely in alignment with data based on 30-year historical expectations.

RESPONDENT:

Winnie Frenzley / Caleb Adcock

WITNESS:

Dr. Ronald E. White / Frank Marino

STF 4.02 BandM 2011 TEP Study.pdf Final

Decommissioning Study of TEP Generating Assets

Prepared For

Tucson Electric Power Company

December 2011

Project No. 63047

Burns & McDonnell
SINCE 1898

Decommissioning Study of

TEP Generating Assets

prepared for

Tucson Electric Power Company
Tucson, Arizona

December, 2011

Project No. 63047

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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* * * * *

1.0 EXECUTIVE SUMMARY

1.1 INTRODUCTION

Burns & McDonnell (BMcD) was retained by Tucson Electric Power Company (TEP), the principle subsidiary of UniSource Energy, to conduct a decommissioning study (Study) for six TEP fossil fuel-fired energy facilities in Arizona. The assets include natural gas, fuel oil, and coal-fired generating facilities. The Study will be used to support future TEP filings with the Arizona Corporation Commission (ACC). TEP authorized a previous decommissioning study for two of the facilities included in this Study; H. Wilson Sundt (HWS) and Springerville Generating Station (SGS). The previous study was conducted in 2002 by Burns and Roe Enterprises, Inc. (BREI). Updates of the BREI decommissioning estimates, along with estimates for the remaining five facilities, are provided within this report. Transmission substation and switchyard facilities are excluded from the decommissioning estimates.

Along with representatives from TEP, BMcD visited all of the sites covered by the Study in August of 2011. The following sites were visited:

- H. Wilson Sundt Generating Station (HWS)
- Springerville Generating Station (SGS)
- Black Mountain Generating Station (BMGS)
- Valencia Power Plant (VPP)
- DeMoss Petrie Generating Station (DPGS)
- North Loop Generating Station (NLGS)

The purpose of the Study was to review the facilities and to make a recommendation to TEP regarding the total cost to decommission and demolish the facilities at the end of their useful lives.

For HWS and SGS, the site decommissioning costs estimated by the Study were developed by using the BREI estimates, which were then updated with revised unit pricing for various decommissioning costs. For the remaining sites, which had not undergone previous decommissioning studies, independent estimates of quantities for the tasks required to be performed for each dismantlement effort were developed by BMcD. Current market labor rates and unit pricing were then developed for each task, and these rates were applied to the quantities for each plant to determine the total cost of decommissioning each site.

1.2 RESULTS

BMcD has prepared estimates in current dollars (October 1, 2011 dollars) for the dismantlement of each of the assets, and these costs are summarized in Table 1.1. When TEP determines that the assets should be retired, portions of the above- and below-grade equipment, steel structures, and other non-ferrous metals are assumed to have sufficient scrap value to a salvage contractor to offset a portion of the site dismantlement costs. The Study assumes that decommissioning will occur at the end of useful life of the facilities and that equipment will only have value as scrap material. TEP will incur costs in the demolition and restoration of the sites, less the scrap value of equipment, bulk steel, and non-ferrous scrap metal.

Table 1.1
DECOMMISSIONING COST SUMMARY

		Dismantlement		Net Project Cost	
Asset	Capacity (MW)	Costs	Credits	($)	($/kW)
HWS	472	$82,479,000	($13,609,000)	$68,870,000	$146/kW
SGS	777	$173,166,000	($12,365,000)	$161,877,000	$208/kW
BMGS	90	$2,014,000	($243,000)	$1,771,000	$20/kW
VPP	68	$1,374,000	($241,000)	$1,133,000	$17/kW
DPGS	75	$1,756,000	($241,000)	$1,515,000	$20/kW
NLGS	95	$2,592,000	($450,000)	$2,142,000	$23/kW
Total	**1,577**	**$263,381,000**	**($27,149,000)**	**$237,308,000**	**$150/kW**

The total project costs presented above include the costs to return the site to a marketable or usable condition. Included are the costs to dismantle the power generating equipment, dismantle balance of plant facilities, dispose of waste materials, and perform site restoration activities. Project indirects such as engineering, site management, owner indirects, etc. are also included in the cost estimates. Appendix A contains dismantlement estimate details for each facility.

* * * * *

2.0 SITE VISITS

Site visits were conducted August 1st through August 5th of 2011. A complete list of the site visit dates is shown in Table 2.1. Site visits consisted of a tour of each facility with plant personnel to review the equipment installed at the site and, for the HWS and SGS plants, discuss changes to the facilities that have occurred since the last study was performed. Tours were conducted by TEP employees Don Gin, Jeff Stevens, John Cannon, and Roger Searles, along with plant personnel at each facility. Site layout drawings for each facility are provided in Appendix B.

Table 2.1
SITE VISIT DATES

Site	Date of Visit
HWS	August 1, 2011
DPGS	August 1, 2011
NLGS	August 1, 2011
VPP	August 2, 2011
SGS	August 4, 2011
BMGS	August 5, 2011

*****

3.0 PLANT DESCRIPTIONS

3.1 H. WILSON SUNDT GENERATING STATION

HWS is located in Tucson, AZ near the intersection of Irvington Road and S. Alvernon Way, on the north side of Interstate 10. The facility consists of four Rankine cycle boilers and two combustion turbines (CTs). The following table provides a summary of the units located at the plant site.

Table 3.1

HWS Summary

Unit	Fuel Type	Nominal Net Capacity	In-Service Date
1	Gas/Oil	81 MW	1958
2	Gas/Oil	81 MW	1960
3	Gas/Oil	104 MW	1962
4	Coal/Gas	156 MW	1967[1]
CT1	Gas/Oil	25 MW	1972
CT2	Gas/Oil	25 MW	1972

[1]Unit 4 was converted from gas/oil to coal/gas in 1988

Each boiler unit consists of the primary boiler, condenser, steam turbine generator (STG), and all supporting systems such as circulating water system, cooling towers, coal pulverizers and bottom ash conveyor system (Unit 4 only), water treatment, process water evaporation ponds, and other balance of plant systems. Units 1 through 3 operate with either natural gas or fuel oil, as they were originally designed. In 1988, Unit 4 was converted to burn coal, oil, or natural gas. In 2003, the oil-firing capability was replaced with landfill gas. Unit 4 continues to operate using these fuels.

The facility includes a significant amount of infrastructure to support unit operations. In addition to the systems described above, the facility also has eight groundwater wells, a booster pump for delivering the city water supply, masonry chimneys, storage tanks for fuel and water, coal unloading and handling equipment, and baghouse and fly ash silos for Unit 4.

In addition to the Rankine cycle boilers at HWS, there are two CTs located at the plant site. The CTs are Westinghouse 251 models (W251). The CTs are fired with either natural gas or fuel oil. Evaporative coolers reduce the inlet air temperature when necessary to improve CT performance. Output from the CTs is transmitted to the plant substation via underground bus duct.

No significant changes have occurred at the plant since the 2002 BREI decommissioning study was completed.

3.2 SPRINGERVILLE GENERATING STATION

SGS is located north of Springerville, AZ, approximately 12 miles east of Highway 180 on County Road 4162. The facility consists of four coal-fired boilers. For purposes of the Study, only Unit 1, Unit 2, and the common facilities that support these units are considered. Units 3 and 4 are not owned by TEP, and are therefore not included in the Study. The following table provides a summary of the two units that are included in the Study.

Table 3.2

SGS Summary

Unit	Fuel Type	Nominal Net Capacity	In-Service Date
1	Coal	387 MW	1985
2	Coal	390 MW	1990

Both units consist of tangentially-fired pulverized coal boilers. In addition to the boilers, primary equipment includes the condensers, STGs, and all supporting systems such as circulating water system, cooling towers, coal pulverizers, water treatment, process water evaporation ponds, and other balance of plant systems.

The facility includes a significant amount of infrastructure to support unit operations. In addition to the systems described above, the facility also has 18 groundwater wells, two raw water ponds, two make-up ponds, a booster pump station for moving water from the wells to the storage ponds, a spray dryer absorber and baghouse for each unit, two (2) 495 feet tall stacks, coal unloading and handling equipment, and numerous administrative, maintenance, and warehouse buildings.

After completion of the BREI study in 2002, Units 3 and 4 were constructed and commissioned. However, with the exception of limited changes to the common facilities of Units 1 and 2 as a result of construction of Units 3 and 4, the newer units are excluded from this Study. Therefore, no significant changes have occurred at the plant that affect this Study since the BREI analysis was completed.

3.3 BLACK MOUNTAIN GENERATING STATION

BMGS is a 2 x General Electric (GE) LM6000 combustion turbine facility. The plant is located on Yuma Road, southwest of Kingman, AZ. The following table provides a summary of the two combustion turbines located at the site.

Table 3.3
BMGS Summary

Unit	Fuel Type	Nominal Net Capacity	In-Service Date
1	Gas	45 MW	2008
2	Gas	45 MW	2008

The plant utilizes inlet chillers to improve output and heat rate during warm ambient conditions. The turbines include spray intercooling to improve performance and reduce emissions. Due to turbine intercooling, the plant includes the equipment necessary to produce demineralized water. Cooling towers for the inlet chillers are also necessary. Wastewater is collected and routed to an onsite evaporation pond. The plant also utilizes a small septic system.

Water is supplied to the plant via one onsite well, one offsite well, and county-supplied water. A 600 kW diesel generator provides back-up power and black start capability. Continuous Emission Monitoring Systems (CEMS) are present on both turbines.

In addition to the plant operating equipment, the facility also includes a metal building that houses a control room, office space, break room, and maintenance facilities. There are several other metal buildings that house various plant equipment such as the chillers, water treatment equipment, air compressors, motor control centers (MCCs), control modules, switchgear, fire pump, etc.

3.4 VALENCIA POWER PLANT

The VPP facility consists of four combustion turbines and their associated equipment. Three of the units are Hitachi Frame 5 turbines, and Unit 4 is a GE LM2500. The plant is located in an area primarily consisting of commercial and retail business in Nogales, AZ. The following table provides a summary of the combustion turbine units located at the plant site.

Table 3.4

VPP Summary

Unit	Fuel Type	Nominal Net Capacity	In-Service Date
1	Gas/Oil	16 MW	1989
2	Gas/Oil	16 MW	1989
3	Gas/Oil	16 MW	1989
4	Gas/Oil	20 MW	2006

All four units are dual fuel, meaning they can burn natural gas or fuel oil. The Frame 5 units have fogging equipment installed for power augmentation when ambient temperatures are high. The LM2500 includes an evaporative cooler. The Frame 5 units are tied together via a reactor that is then connected to a generator step up transformer (GSU) in the switchyard. The LM2500 has a separate GSU. CEMS equipment is installed on all four units, and the LM2500 has water injection to reduce nitrous oxide (NO_x) emissions and increase performance.

Balance of plant equipment at the site includes two air compressors, a starting motor for the LM2500, a 550 kW diesel generator that provides black start capability, and various tanks and sumps. A large building provides office space and maintenance facilities.

Water is supplied to the plant via a city-supplied connection. A separate city connection is utilized for fire suppression. Due to potential contamination from previous site uses, there are 25 monitoring wells onsite that range from 100 feet to 300 feet in depth.

3.5 DEMOSS PETRIE GENERATING STATION

DPGS consists of a single GE 7FA combustion turbine unit. The plant is located in Tucson, AZ, directly east of Interstate 10 on North Flowing Wells Road. The unit at DPGS is described in the following table.

Table 3.5

DPGS Summary

Unit	Fuel Type	Nominal Net Capacity	In-Service Date
1	Gas	75 MW	2001

The 7EA combustion turbine at DPGS is fired with natural gas only. However, there is a fuel oil tank present that was used for units that were originally at the site but were removed prior to installation of the combustion turbine.

In addition to the combustion turbine unit, other plant equipment includes a starting motor, gas metering and regulation station, water tank, water wash skid, lube oil skid, reverse osmosis water treatment building, CEMS building, air compressor skid, and a maintenance building. The plant has two onsite wells for water supply and a water tower for storage.

3.6 NORTH LOOP GENERATING STATION

The NLGS consists of four combustion turbines and their associated equipment. Three of the units are W251 models, and the remaining unit is a GE LM2500. The plant is located in Marana, AZ, just east of Interstate 10 on Case Grande Highway. The following table provides a summary of the combustion turbine units located at the plant site.

Table 3.6

NLGS Summary

Unit	Fuel Type	Nominal Net Capacity	In-Service Date
1	Gas/Oil	25 MW	1972
2	Gas/Oil	25 MW	1972
3	Gas/Oil	25 MW	1972
4	Gas	20 MW	2001

The W251 turbines are dual fuel capable and have evaporative coolers. These turbines are essentially identical to the units installed at HWS. The LM2500 turbine has an evaporative cooler, as well as water injection for decreased NO_X emissions and increased performance. CEMS equipment is installed on the LM2500. All four units are interconnected with a common GSU.

Balance of plant equipment at the site includes reverse osmosis water treatment for the LM2500 water injection as well as use in the evaporative coolers when blended with well water, switchgear, water separator for the natural gas, fuel oil storage tank and pipeline, and diesel starting motors. The site also includes a small office/guard shack, brick enclosure around the GSU, several skids for the LM2500, and a small septic system.

* * * * *

4.0 DECOMMISSIONING COSTS

BMcD prepared decommissioning estimates for the TEP-owned generating assets described in this Study. When TEP determines that the assets should be retired, the above grade equipment, steel structures, some below grade materials, and other non-ferrous metals are assumed to have sufficient scrap value to a salvage contractor to offset a portion of the site dismantlement costs. The Study assumes that decommissioning will occur at the end of useful life of the facilities and equipment will only have value as scrap material. TEP will incur costs in the demolition and restoration of the sites less the scrap value of equipment, bulk steel, and non-ferrous scrap metal.

The decommissioning estimates include the cost to return the sites to a marketable or useable condition. The estimates include the costs to dismantle all of the assets owned by TEP at each site, including power generating equipment and balance of plant facilities. Site restoration is also included. Transmission substation and switchyard facilities are excluded from the decommissioning estimates.

TEP authorized a previous decommissioning study for two of the facilities included in this Study; HWS and SGS. The BREI-conducted study was completed in 2002. For these two facilities, BMcD relied upon the estimated quantities for bulk materials developed by BREI. The unit pricing associated with dismantling and disposing of these materials has been updated by Burns & McDonnell. Likewise, scrap values have been updated to reflect current market conditions. For the remaining facilities, BMcD has developed bulk quantity estimates based on review of the sites and BMcD's and/or manufacturers' in-house data for plant equipment quantities. This resulted in a full estimate of quantities for the tasks required to be performed for each dismantlement effort. Current market labor rates and unit pricing were then developed for each task, and these rates were applied to the quantities for each plant to determine the total cost of decommissioning for each site.

For purposes of this study, BMcD has assumed that each site will be demolished as a single project, allowing the most cost effective demolition methods to be utilized. A summary of several of the means and methods that could be employed is summarized in the following paragraphs; however, means and methods will not be dictated to the contractor by TEP or BMcD. It will be the contractor's responsibility to determine means and methods that result in safely dismantling the facilities at the lowest possible cost.

Asbestos remediation would take place prior to commencement of any other demolition activities and is not included in the scope of this decommissioning analysis. Abatement would need to be performed in

compliance with all state and federal regulations, including, but not limited to requirements for sealing off work areas and maintaining negative pressure throughout the removal process. Final clearances and approvals would need to be achieved prior to performing further demolition activities.

High grade assets would then be removed from the site, to the extent possible. This would include items such as transformers, transformer coils, circuit breakers, electrical wire, condenser plates and tubes, and heater tubes. High grade assets include precious alloys such as copper, aluminum-brass tubes, titanium tubes, inconel, and other high value metals occurring in plant systems. High grade asset removal would occur up-front in the schedule, to reduce the potential for vandalism, to increase cash flow, and for separation of recyclable materials, in order to increase scrap recovery. Methods of removal vary with the location and nature of the asset. Small transformers, small equipment, and wire would likely be removed and shipped as-is for processing at a scrap yard. Large transformers, combustion turbines, steam turbines, and condensers would likely require some on-site disassembly prior to being shipped to a scrap yard.

Construction and Demolition (C&D) waste includes items such as non-asbestos insulation, roofing, wood, drywall, plastics, and other non-metallic materials. C&D waste would typically be segregated from scrap and concrete to avoid cross-contaminating of waste streams or recycle streams. C&D demolition crews would remove these materials with equipment such as excavators equipped with material handling attachments, skid steers, etc. This material would be consolidated and loaded into bulk containers for disposal.

In general, boilers could be felled and dismantled by cutting them into manageable sized pieces on the ground. First, the structures around the boilers would need to be removed using excavators equipped with shears and grapples. Stairs, grating, elevators, and other high structures would be removed using an "ultra high reach" excavator, equipped with shears. Following removal of these structures, the boilers would then be dismantled using equipment such as excavators equipped with shears and grapples and the scrap metal would be loaded onto trailers for recycling.

After the surrounding structures and ductwork have been removed, the stacks would be imploded, using controlled blasts. Following implosion, the stack liners and concrete would be reduced in size to allow for handling and removal.

Balance of plant structures and foundations would likely be demolished using excavators equipped with hydraulic shears, hydraulic grapples, and impact breakers, along with workers utilizing open flame cutting

torches. Steel components would be separated, reduced in size, and loaded onto trailers for recycling. Concrete would be broken into manageable sized pieces and stockpiled for crushing on-site. Concrete pieces would ultimately be loaded in a hopper and fed through a crusher to be sized for on-site disposal, if suitable. Remaining material would be disposed of in off-site landfills.

4.1 GENERAL DECOMMISSIONING ASSUMPTIONS FOR ALL SITES

The following assumptions were made as the basis for all the cost estimates:

1. The estimates are inclusive of all cost necessary to properly dismantle all sites to a marketable or usable condition.
2. All facilities and units within each station will be decommissioned to zero generating output. Existing utilities will remain in place for use by the contractor for the duration of the demolition activities.
3. All work will take place in the most cost efficient method.
4. Labor costs are based on a regular 40 hour workweek without overtime.
5. It is assumed that plants with multiple units will be dismantled at one time. If retirement dates vary for multiple units at a single site, decommissioning activities will take place once the last unit has been retired.
6. All demolition and abatement activities will be performed in compliance with all federal, state and local requirements and regulations.
7. TEP will remove all coal, fuel oil, vehicle fuel, limestone/lime, and chemicals prior to commencement of demolition activities.
8. TEP will remove all rolling stock (rail cars, vehicles, cranes, forklift trucks, etc.) and temporary vehicle fuel tanks prior to commencement of demolition activities.
9. TEP will remove any spare parts, tools, inventory, or equipment in the buildings prior to commencement of demolition activities.
10. Hazardous material abatement is included for known materials. Specific exceptions are discussed in the site specific assumptions.
11. There are no polychlorinated biphenyls (PCBs) at any of the sites.
12. Demolition will include the removal of all structures, equipment, boilers, tanks, conveying and ancillary buildings, and any other associated equipment and facilities to four feet below grade for foundations and slabs. All structures below four feet will be abandoned in-place unless deemed hazardous by TEP or otherwise stated in the assumptions as being demolished.

13. Circulating water system pipes will be capped, have the tops broken out, and backfilled with on-site soil.
14. All other underground piping below four feet will be abandoned in place by capping each end with concrete.
15. Foundations and piles below four feet will be abandoned in place.
16. Storm sewers, catch basins and ducts will be collapsed to four feet below grade where possible, filled and sealed on the upstream side. Horizontal runs will be abandoned in place after being closed.
17. With the exception of soil replacement for ponds, the cost estimates assume that site materials balance without any import or export of fill material.
18. All ponds will be drained by evaporation methods.
19. Step up transformers, auxiliary transformers, and spare transformers are included for demolition and scrap in all estimates. TEP will remove and dispose of transformer oil prior to commencement of demolition activities.
20. Transmission switchyards and substations within the property limits of the plant are not part of the demolition scope. The generator step-up transformers and generator lead lines to the switchyards will be removed. Remaining switchyard equipment is assumed to be part of the transmission system assets and will remain in-place following demolition activities.
21. Remediation work activities include collecting, draining, and disposing of residual oils from tanks.
22. Costs are included to clean out all fuel oil tanks. Costs have also been included to remove one foot of soil directly below each of the fuel oil tanks to account for the potential for this soil to be contaminated during normal operations.
23. Soil testing and any other on-site testing has not been conducted for this study.
24. No environmental costs have been included to address site clean-up of contaminated soils, hazardous materials, or other conditions present on-site having a negative environmental impact, other than those specifically listed in these assumptions. No allowances are included for unforeseen environmental remediation activities.
25. Site areas will be graded to achieve suitable site drainage to natural drainage patterns, but grading will be minimized to the extent possible.
26. For purposes of this study, it is assumed that none of the equipment will have a salvage value in excess of the scrap value of the materials in the equipment at the time of the decommissioning study. The decommissioning cost estimates are based on the end of useful life of each facility.

All equipment, steel, copper, and other metals will be sold as scrap. Credits for salvage value are based on scrap value alone. Resale of equipment and materials is not included.

27. Major equipment and structural steel is included for scrap value. All other demolished materials are considered debris.
28. Scrap values were determined using the American Metals Market report for September of 2011, based on costs for the Study area.
29. Scrap value of steel is included at $250 per ton, less hauling costs from the site.
30. Scrap value of copper is included at $3,000 per ton, less hauling costs from the site.
31. Scrap value of 304 stainless steel is $1,600 per ton, less hauling costs from the site.
32. Engineering costs include preparing detailed work plans, obtaining site permits, respiratory protection, hazardous communication, Occupational Safety and Health Administration (OSHA) engineering survey, detailed schedule, and site specific health and safety plans.
33. Valuation and sale of land and all replacement generation costs are excluded from this scope.
34. Contingency of 20% has been included in the estimate and is provided as a separate item.
35. Pricing for all estimates is based on October 1, 2011 dollars.
36. The scope of the costs included in this Study is limited to the decommissioning activities that will occur at the end of useful life of the facilities. Additional on-going costs may be required, including, but not limited to groundwater monitoring and/or other environmental monitoring activities. These costs are excluded from the cost estimates provided in this Study.

4.2 SITE SPECIFIC DECOMMISSIONING ASSUMPTIONS

The previous section provided the general decommissioning assumptions that were used for all sites in the Study. The following sections provide specific assumptions and/or clarifications to the general assumptions for each plant.

4.2.1 H. WILSON SUNDT GENERATING STATION

The following assumptions were made specific to HWS:

1. Bulk material quantities were provided by the 2002 BREI study. These quantities were adjusted slightly to account for materials that are more than four feet below grade and will be left in place. The 2002 BREI study did not include the two (2) W251 combustion turbines located at the site. The turbines are included in this Study.

2. BMcD developed independent unit costs for dismantling, scrapping, and disposing of bulk materials. These unit costs were applied to the adjusted BREI study quantities to arrive at the decommissioning cost estimate.
3. The 2002 BREI study did not include costs for pond closures, closure of the coal pile area, cleanup of the fuel oil tank areas (soil disposal), and other environmental considerations. These items are included in this Study.
4. There is no asbestos abatement cost included in the estimate. However, some asbestos is anticipated to be encountered. An asbestos survey is necessary in order to quantify the removal and disposal costs.
5. Piles and other subsurface materials that are more than four feet below the surface will remain in place.
6. A mercury survey was not available for review. Standard removal and disposal costs were included.
7. There is no known lead-based paint at the plant. However, testing during demolition is recommended for confirmation.
8. The plant has 13 Cesium 137 devices for hoppers and chutes. Costs for removing and disposing of these devices are included.
9. Demolition activities for the coal pile area and fuel tank area include removing and disposing of 12 inches of soil, replacing that soil, grading, adding topsoil, fine grading, and hydroseeding.
10. Demolition activities of the evaporation ponds include grading of the berms and pond area, adding topsoil, fine grading, and hydroseeding.
11. Demolition activities for the process wastewater ponds include rough grading, installation of a 40 mil high density polyethylene (HDPE) liner, geo-net drainage layer, 12 inches of soil and 6 inches of topsoil, fine grading, and hydroseeding.

4.2.2 SPRINGERVILLE GENERATING STATION

The following assumptions were made specific to SGS:

1. Units 3 and 4 are excluded from the decommissioning estimate. Decommissioning costs are provided for Units 1 and 2 only, as well as common facilities that support the plant. TEP owns or leases all of the common facilities, including the coal handling facilities. TEP is fully responsible for all costs associated with the common and fuel handling assets.
2. The two well field storage ponds are shared evenly between all units at the site. TEP's retirement obligation for these ponds is 50% of the total decommissioning cost.

3. Bulk material quantities were provided by the 2002 BREI study. These quantities were adjusted slightly to account for materials that are more than four feet below grade and will be left in place.
4. BMcD developed independent unit costs for dismantling, scrapping, and disposing of bulk materials. These unit costs were applied to the adjusted BREI study quantities to arrive at the decommissioning cost estimate.
5. The 2002 BREI study did not include costs for landfill closure, pond closures, closure of the coal pile area, cleanup of the vehicle fueling area (soil disposal), removal of the plant entrance road, and other environmental considerations. These items are included in this Study.
6. There is no asbestos abatement cost included. The plant does not have any known asbestos materials.
7. The onsite landfill will be used to dispose of inert debris such as concrete and metals with no salvage value. No transportation or landfill fees are included for these items.
8. Piles and other subsurface materials that are more than four feet below the surface will remain in place.
9. A mercury survey was not available for review. Standard removal and disposal costs were included.
10. There is no known lead-based paint at the plant. However, testing during demolition is recommended for confirmation.
11. The plant has 112 Cesium 137 devices for baghouse level detection and coal feed measurements. Costs for removing and disposing of these devices are included.
12. Demolition activities for the coal pile area include removing and disposing of 12 inches of soil, replacing that soil, grading, adding topsoil, fine grading, and hydroseeding.
13. Demolition activities of the wastewater ponds and water storage ponds include grading of the berms and pond area, adding topsoil, fine grading, and hydroseeding.
14. Demolition activities for the process wastewater and sewage ponds as well as the ash landfill include rough grading, installation of a 40 mil HDPE liner, geo-net drainage layer, 12 inches of soil and 6 inches of topsoil, fine grading, and hydroseeding.

4.2.3 BLACK MOUNTAIN GENERATING STATION

The following assumptions were made specific to BMGS:

1. The plant has no known lead-based paint.
2. The plant has no mercury-containing devices.

3. Weights for the LM6000 combustion turbines and their major components were obtained from equipment manufacturer datasheets.
4. Weights of various metals contained within major transformers were obtained from the transformer nameplate or from manufacturer datasheets.
5. Demolition activities of the wastewater pond include grading of the berms and pond area, adding topsoil, fine grading, and hydroseeding.

4.2.4 VALENCIA POWER PLANT

The following assumptions were made specific to VPP:

1. The plant has no known lead-based paint.
2. A mercury survey was not available for review. Standard removal and disposal costs were included.
3. The existing groundwater monitoring wells will remain in place following plant decommissioning.
4. Demolition activities for the fuel tank area include removing and disposing of 12 inches of soil, replacing that soil, grading, adding topsoil, fine grading, and hydroseeding.
5. Weights for the LM2500 and Hitachi Frame 5 combustion turbines and their major components were obtained from equipment manufacturer datasheets.
6. Weights of various metals contained within major transformers were obtained from the transformer nameplate or from manufacturer datasheets.

4.2.5 DEMOSS PETRIE GENERATING STATION

The following assumptions were made specific to DPGS:

1. The plant has no known lead-based paint.
2. A mercury survey was not available for review. Standard removal and disposal costs were included.
3. The fuel oil tank, which is currently not in use, will be removed during decommissioning.
4. Demolition activities for the fuel tank area include removing and disposing of 12 inches of soil, replacing that soil, grading, adding topsoil, fine grading, and hydroseeding.
5. Weights for the GE 7EA combustion turbine and its major components were obtained from equipment manufacturer datasheets.

6. Weights of various metals contained within major transformers were obtained from the transformer nameplate or from manufacturer datasheets.

4.2.6 NORTH LOOP GENERATING STATION

The following assumptions were made specific to NLGS:

1. The plant has no known lead-based paint.
2. A mercury survey was not available for review. Standard removal and disposal costs were included.
3. The fuel oil tank, which is north of the substation that will remain following plant retirement, will be removed during decommissioning.
4. Demolition activities for the fuel tank area include removing and disposing of 12 inches of soil, replacing that soil, grading, adding topsoil, fine grading, and hydroseeding.
5. Weights for the LM2500 and W251 combustion turbines and their major components were obtained from equipment manufacturer datasheets.
6. Weights of various metals contained within major transformers were obtained from the transformer nameplate or from manufacturer datasheets.

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5.0 LIMITATIONS

In preparation of this dismantlement cost study, BMcD has relied upon information provided by TEP. BMcD acknowledges that it has requested the information from TEP that it deemed necessary to complete this study. While we have no reason to believe that the information provided to us, and upon which we have relied, is inaccurate or incomplete in any material respect, we have not independently verified such information and cannot guarantee its accuracy or completeness.

Engineer's estimates and projections of demolition costs are based on Engineer's experience, qualifications and judgment. Since Engineer has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractors' procedures and methods, and other factors, Engineer does not guarantee the accuracy of its estimates and projections.

Engineer's estimates do not include allowances for unforeseen environmental liabilities associated with unexpected environmental contamination due to events not considered part of normal operations, such as fuel tank ruptures, oil spills, etc. Estimates also do not include allowances for environmental remediation associated with changes in classification of hazardous materials.

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APPENDIX A – DECOMMISSIONING COST ESTIMATES

H. Wilson Sundt

HWS Units 1, 2, 3, and 4 and CT 1 and 2 - Dismantlement Estimate

Task/Description	Demo Quantity	Scrap Quantity	Units	Demo $/Unit	Scrap $/Unit	Manhours	$/Manhour	Manhour Cost	Demo Cost	Scrap Credit	Total Cost
Units 1 and 2											
1. Civil Work											
a. Below Grade Utilities	128	28	Tons	$232.76	($165.00)	n/a			$29,793	($4,224)	$25,569
b. Excavation and Backfill	-	-	-			1626	$66.41	$107,966	n/a	n/a	$107,966
c. Concrete Foundations	24,700	-	Tons	$40.23	n/a	n/a			$993,681	n/a	$993,681
d. Structural & Misc. Steel	230	230	Tons	$232.76	($165.00)	n/a			$53,535	($37,950)	$15,585
e. Turbine Bldg & Control Room	190	-	Tons	$232.76	n/a	n/a			$44,224	n/a	$44,224
f. Disposal											
i. Waste Hauling (10 mi haul)	24,992		Tons	$8.04	n/a	n/a			$200,994	n/a	$200,994
ii. Landfill Fees	24,992		Tons	$45.68	n/a	n/a			$1,141,528	n/a	$1,141,528
2. Mechanical Work											
a. Boiler	14,400	11,520	Tons	$232.76	($165.00)	n/a			$3,351,725	($1,900,800)	$1,450,929
b. Steam Turbine @ 81 MW	1,960	1,294	Tons	$232.76	($165.00)	n/a			$456,209	($213,444)	$242,764
c. BOP Equipment	2,900	-	Tons	$232.76	n/a	n/a			$675,001	n/a	$675,001
d. BOP Mechanical Bulks	1,058	835	Tons	$232.76	($165.00)	n/a			$246,259	($104,742)	$141,517
e. Disposal											
i. Waste Hauling (10 mi haul)	6,870		Tons	$8.04	n/a	n/a			$55,247	n/a	$55,247
ii. Landfill Fees	6,870		Tons	$45.68	n/a	n/a			$313,769	n/a	$313,769
3. Electrical and I&C Work											
a. Equipment	1,300	-	Tons	$232.76	n/a	n/a			$302,587	n/a	$302,587
b. Electrical Bulks	250	150	Tons	$232.76	($2,290.00)	n/a			$58,190	($343,500)	($285,310)
c. Disposal											
i. Waste Hauling (10 mi haul)	1,400		Tons	$8.04	n/a	n/a			$11,259	n/a	$11,259
ii. Landfill Fees	1,400		Tons	$45.68	n/a	n/a			$63,945	n/a	$63,945
Total Net Demolition Cost (One 81 MW Unit)											**$5,581,274**
Total Net Demolition Cost (Two 81 MW Units)											**$11,162,548**
Unit 3											
1. Civil Work											
a. Below Grade Utilities	144	29	Tons	$232.76	($165.00)	n/a			$33,517	($4,752)	$28,765
b. Excavation and Backfill	-	-	-			2100	$66.41	$139,468	n/a	n/a	$139,468
c. Concrete Foundations	27,550	-	Tons	$40.23	n/a	n/a			$1,108,337	n/a	$1,108,337
d. Structural & Misc. Steel	255	255	Tons	$232.76	($165.00)	n/a			$59,354	($42,075)	$17,279
e. Turbine Bldg & Control Room	205	-	Tons	$232.76	n/a	n/a			$47,716	n/a	$47,716
f. Disposal											
i. Waste Hauling (10 mi haul)	27,870		Tons	$8.04	n/a	n/a			$224,138	n/a	$224,138
ii. Landfill Fees	27,870		Tons	$45.68	n/a	n/a			$1,272,971	n/a	$1,272,971
2. Mechanical Work											
a. Boiler	15,600	12,480	Tons	$232.76	($165.00)	n/a			$3,631,040	($2,059,200)	$1,571,840
b. Steam Turbine @ 104 MW	2,270	1,496	Tons	$232.76	($165.00)	n/a			$528,383	($247,203)	$281,180
c. BOP Equipment	3,575	-	Tons	$232.76	n/a	n/a			$832,113	n/a	$832,113
d. BOP Mechanical Bulks	1,400	840	Tons	$232.76	($165.00)	n/a			$325,863	($138,600)	$187,263
e. Disposal											
i. Waste Hauling (10 mi haul)	8,027		Tons	$8.04	n/a	n/a			$64,553	n/a	$64,553
ii. Landfill Fees	8,027		Tons	$45.68	n/a	n/a			$366,624	n/a	$366,624
3. Electrical and I&C Work											
a. Equipment	1,470	-	Tons	$232.76	n/a	n/a			$342,156	n/a	$342,156
b. Electrical Bulks	250	150	Tons	$232.76	($2,290.00)	n/a			$58,190	($343,500)	($285,310)
c. Disposal											
i. Waste Hauling (10 mi haul)	1,570		Tons	$8.04	n/a	n/a			$12,626	n/a	$12,626
ii. Landfill Fees	1,570		Tons	$45.68	n/a	n/a			$71,710	n/a	$71,710
Total Net Demolition Cost (One 104 MW Unit)											**$5,283,406**
Unit 4											
1. Civil Work											
a. Below Grade Utilities	184	37	Tons	$232.76	($165.00)	n/a			$42,828	($6,972)	$35,756
b. Excavation and Backfill	-	-	-			2668	$66.41	$178,516	n/a	n/a	$178,516
c. Concrete Foundations	35,264	-	Tons	$40.23	n/a	n/a			$1,418,671	n/a	$1,418,671
d. Structural & Misc. Steel	326	326	Tons	$232.76	($165.00)	n/a			$75,879	($53,790)	$22,089
e. Turbine Bldg & Control Room	262	-	Tons	$232.76	n/a	n/a			$60,963	n/a	$60,963
f. Disposal											
i. Waste Hauling (10 mi haul)	35,573		Tons	$8.04	n/a	n/a			$286,891	n/a	$286,891
ii. Landfill Fees	35,573		Tons	$45.68	n/a	n/a			$1,629,373	n/a	$1,629,373
2. Mechanical Work											
a. Boiler	19,968	15,974	Tons	$232.76	($165.00)	n/a			$4,647,731	($2,635,776)	$2,011,955
b. Steam Turbine @ 156 MW	2,905	1,918	Tons	$232.76	($165.00)	n/a			$676,398	($316,463)	$359,934
c. BOP Equipment	4,576	-	Tons	$232.76	n/a	n/a			$1,065,105	n/a	$1,065,105
d. BOP Mechanical Bulks	1,792	1,075	Tons	$232.76	($165.00)	n/a			$417,104	($177,408)	$239,696
e. Disposal											
i. Waste Hauling (10 mi haul)	10,274		Tons	$8.04	n/a	n/a			$82,629	n/a	$82,629
ii. Landfill Fees	10,274		Tons	$45.68	n/a	n/a			$469,285	n/a	$469,285
3. Electrical and I&C Work											
a. Equipment	1,882	-	Tons	$232.76	n/a	n/a			$438,052	n/a	$438,052
b. Electrical Bulks	365	219	Tons	$232.76	($2,290.00)	n/a			$84,957	($501,510)	($416,553)
c. Disposal											
i. Waste Hauling (10 mi haul)	2,028		Tons	$8.04	n/a	n/a			$16,310	n/a	$16,310
ii. Landfill Fees	2,028		Tons	$45.68	n/a	n/a			$92,629	n/a	$92,629
Total Net Demolition Cost (One 156 MW Unit)											**$7,982,322**

H. Wilson Sundt, cont.

HWS Units 1, 2, 3, and 4 and GT 1 and 2 - Dismantlement Estimate											
Task/Description	Demo Quantity	Scrap Quantity	Units	Demo $/Unit	Scrap $/Unit	Manhours	$/Manhour	Manhour Cost	Demo Cost	Scrap Credit	Total Cost
Common Area											
1. Common Facilities											
a. Flue Gas System	7,500	-	Tons	$232.76		n/a			$1,745,682	n/a	$1,745,682
b. Cooling Towers	2,000	-	Tons	$232.76		n/a			$465,518	n/a	$465,518
c. Bottom Ash	420	-	Tons	$232.76		n/a			$97,759	n/a	$97,759
d. Coal Handling Yard	160	-	Tons	$232.76		n/a			$37,241	n/a	$37,241
e. Lime Unloading	88	-	Tons	$232.76		n/a			$20,483	n/a	$20,483
f. Admin Building	510	-	Tons	$232.76		n/a			$118,707	n/a	$118,707
g. Stack:	-	-	-								
i. Outer Concrete	9,821	-	Tons	$40.23		n/a			$395,109	n/a	$395,109
ii. Steel Liner	52	-	Tons	$232.76		n/a			$12,103	n/a	$12,103
h. Below Grade:											
i. Duct Banks	7,776	-	Tons	$40.23		n/a			$312,828	n/a	$312,828
ii. Sanitary Sewer	-	-	-			264	$66.43	$17,533	n/a	n/a	$17,533
iii. Oil System	40	40	-	$232.76	($165.00)	n/a			$9,310	($6,600)	$2,710
iv. Concrete Foundations	81,759	-	Tons	$40.23		n/a			$3,289,180	n/a	$3,289,180
v. Rail Road Track Removal	1,200	1,200	Tons	$232.76	($165.00)	n/a			$279,311	($198,000)	$81,311
i. Tanks (13) Clng. & Demo	9,550	9,550	Tons	$232.76	($165.00)	n/a			$2,222,648	($1,575,750)	$647,098
j. Site Restoration & Seeding	275	-	Acres	$6,884.53		n/a			$1,893,245	n/a	$1,893,245
k. Disposal											
i. Waste Hauling (10 mi haul)	110,087	-	Tons	$8.04	n/a	n/a			$885,339	n/a	$885,339
ii. Landfill Fees	110,087	-	Tons	$45.68	n/a	n/a			$5,028,207	n/a	$5,028,207
2. Environmental Cleanup											
a. Ponds/Coal Area Closures											
- Coal Pile Area											$3,873,000
- Process Water Ponds											$490,000
- Evaporation Ponds											$340,000
b. ACM Removal/Disposal											n/a
c. PCB Disposal											n/a
d. Refractory Disposal											$61,750
e. Plant Washdown & Disposal											$61,000
f. Mercury Disposal											$11,270
g. Fuel Oil Tank Soil Disposal											$5,289,994
h. Nuclear Device Disposal											$31,500
Total Net Demolition Cost - Common Area											**$35,196,577**
Units 1, 2, 3, and 4 - 25 MW Combustion Turbines											
a. Turbine Skid & Gear Pedestal	110	88	Tons	$232.76	($165.00)	n/a			$25,603	($14,520)	$11,083
b. Generator and Exciter Package	116	58	Tons	$232.76	($165.00)	n/a			$26,884	($9,529)	$17,355
c. Diesel Starting Package	12	6	Tons	$232.76	($165.00)	n/a			$2,677	($949)	$1,728
d. Mechanical Skid	21	11	Tons	$232.76	($165.00)	n/a			$4,888	($1,733)	$3,155
e. Control - Electric Skid	53	26	Tons	$232.76	($165.00)	n/a			$12,220	($4,331)	$7,889
f. Air/Air Cooler & Supports	6	3	Tons	$232.76	($165.00)	n/a			$1,397	($495)	$902
g. Lube Oil Cooler with Lube Oil in Tubes	17	8	Tons	$232.76	($165.00)	n/a			$3,841	($1,361)	$2,479
h. Inlet System	34	17	Tons	$232.76	($165.00)	n/a			$7,797	($2,764)	$5,034
i. Gas Turbine Enclosure	40	20	Tons	$232.76	($165.00)	n/a			$9,310	($3,300)	$6,010
j. Exhaust System	84	42	Tons	$232.76	($165.00)	n/a			$19,552	($6,930)	$12,622
k. Appearance & Acoustical Lagging	9	5	Tons	$232.76	($165.00)	n/a			$2,095	($743)	$1,352
l. Disposal											
i. Waste Hauling (10 mi haul)	218		Tons	$8.04	n/a	n/a			$1,733	n/a	$1,733
ii. Landfill Fees	215		Tons	$45.68	n/a	n/a			$9,843	n/a	$9,843
Total Net Demolition Cost (One 25 MW Unit)											**$81,185**
Total Net Demolition Cost (Two 25 MW Units)											**$162,371**
TOTAL COST (CREDIT)											**$58,639,225**
PROJECT INDIRECTS											
a. Contractor Indirects 5% of Total Cost											$2,932,000
b. Engineering											$1,519,000
c. Construction Management											$1,013,000
d. Owner Indirects											$2,026,000
e. Performance Bond											$1,013,000
CONTINGENCY (20%)											$10,128,000
TOTAL NET PROJECT COST ($)											**$80,670,000**
TOTAL NET PROJECT COST ($/kW)											**$146**

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Springerville Generating Station

SGS Units 1 and 2 - Dismantlement Estimate

Task/Description	Demo Quantity	Scrap Quantity	Units	Demo $/Unit	Scrap $/Unit	Manhours	$/Manhour	Manhour Cost	Demo Cost	Scrap Credit	Total Cost
1. Civil Work											
a. Below Grade Utilities	314	63	Tons	$272.04	($165.00)	n/a			$85,311	($10,349)	$74,962
b. Excavation and Backfill	-	-	-		n/a	4,566	$80.01	$365,930	n/a	n/a	$365,930
c. Concrete Foundations	60,181	-	Tons	$40.23	n/a	n/a			$2,420,263	n/a	$2,420,263
d. Structural & Misc. Steel	624	624	Tons	$272.04	($165.00)	n/a			$169,751	($102,960)	$66,791
e. Turbine Bldg & Control Room	447	-	Tons	$272.04	n/a	n/a			$121,601	n/a	$121,601
f. Disposal											
i. Waste Hauling (10 mi haul)	-	-	Tons	$7.23	n/a	n/a			n/a	n/a	n/a
ii. Landfill Fees	-	-	Tons	$45.68	n/a	n/a			n/a	n/a	n/a
2. Mechanical Work											
a. Boiler	34,085	27,252	Tons	$272.04	($165.00)	n/a			$9,295,943	($4,496,580)	$4,770,363
b. Steam Turbine @ 387 MW	2,906	1,918	Tons	$272.04	($165.00)	n/a			$790,540	($316,463)	$474,076
c. BOP Equipment	7,807	-	Tons	$272.04	n/a	n/a			$2,123,793	n/a	$2,123,793
d. BOP Mechanical Bulks	3,057	1,834	Tons	$272.04	($165.00)	n/a			$831,617	($302,643)	$528,974
e. Disposal											
i. Waste Hauling (10 mi haul)	-	-	Tons	$7.23	n/a	n/a			n/a	n/a	n/a
ii. Landfill Fees	-	-	Tons	$45.68	n/a	n/a			n/a	n/a	n/a
3. Electrical and I&C Work											
a. Equipment	3,199	-	Tons	$272.04	n/a	n/a			$870,247	n/a	$870,247
b. Electrical Bulks	514	368	Tons	$272.04	($2,290.00)	n/a			$167,091	($843,636)	($676,605)
c. Disposal											
i. Waste Hauling (10 mi haul)	-	-	Tons	$7.23	n/a	n/a			n/a	n/a	n/a
ii. Landfill Fees	-	-	Tons	$45.68	n/a	n/a			n/a	n/a	n/a
Net Demolition Cost (One 387 MW Unit)											$11,141,395 ①
Net Demolition Cost (Two 387 MW Units)											$22,282,789
1. Common Facilities											
a. Flue Gas System	28,000	-	Tons	$272.04	n/a	n/a			$7,617,038	n/a	$7,617,038
b. Cooling Towers	1,000	-	Tons	$272.04	n/a	n/a			$272,037	n/a	$272,037
c. Bottom Ash	1,680	-	Tons	$272.04	n/a	n/a			$457,022	n/a	$457,022
d. Coal Handling Yard	400	-	Tons	$272.04	n/a	n/a			$108,815	n/a	$108,815
e. Lime Unloading	220	-	Tons	$272.04	n/a	n/a			$59,848	n/a	$59,848
f. Admin. Building	510	-	Tons	$272.04	n/a	n/a			$138,739	n/a	$138,739
g. Stacks - 2 (two):											
ii. Outer Concrete	25,515	-	Tons	$40.23	n/a	n/a			$1,026,468	n/a	$1,026,468
iii. Steel Liner	130	130	Tons	$272.04	($165.00)	n/a			$35,365	($21,450)	$13,915
h. Below Grade:											
i. Duct Banks	7,778	-	Tons	$40.23	n/a	n/a			$312,828	n/a	$312,828
ii. Sanitary Sewer	-	-	-		n/a	264	$80.01	$21,123	n/a	n/a	$21,123
iii. Concrete Foundations	65,408	-	Tons	$40.23	n/a	n/a			$2,631,344	n/a	$2,631,344
iv. Rail Road Track Removal	1,200	1,200	Tons	$272.04	($165.00)	n/a			$326,444	($198,000)	$128,444
i. Site Restoration & Seeding	1,350	-	Acres	$7,655.97	n/a	n/a			$10,335,561	n/a	$10,335,561
j. Disposal											
i. Waste Hauling (10 mi haul)	-	-	Tons	$7.23	n/a	n/a			n/a	n/a	n/a
ii. Landfill Fees	-	-	Tons	$45.68	n/a	n/a			n/a	n/a	n/a
k. Plant Entrance Road	64,530	-	SY	$13.60	n/a	n/a			$877,608	n/a	$877,608
2. Environmental Cleanup											
a. Landfill / Pond Closures											
- Coal Pile Area											$11,774,283
- Coal Pile Runoff Pond											$1,087,584
- Evaporation Ponds (8)											$5,028,485
- Process Water Ponds (5)											$1,868,299
- Sludge Ponds (4)											$1,004,925
- Make-Up Water Ponds (2)											$1,264,586
- Raw Water Storage Ponds (2)											$1,225,488
- Sewage Ponds (2)											$681,012
- Const. Run-Off Pond #1											$986,647
- Const. Run-Off Pond #2											$979,200
- Well Field Storage Ponds (2) [1]											$197,240
- Ash Landfill											$46,041,171
b. ACM Removal/Disposal											n/a
c. PCB Disposal											n/a
d. Refractory Disposal											$73,150
e. Plant Washdown & Disposal											$122,000
f. Mercury Disposal											$11,270
g. Vehicle Fuel Oil Tank Soil Disposal											$132,228
h. Nuclear Device Disposal											$259,000
Total Net Demolition Cost - Common Area											$96,744,307
TOTAL COST (CREDIT)											$119,027,096
PROJECT INDIRECTS											
a. Contractor Indirects 5% of Total Cost											$5,951,000
b. Engineering											$3,571,000
c. Construction Management											$2,381,000
d. Owner Indirects											$4,761,000
e Performance Bond											$2,381,000
CONTINGENCY (20%)											$23,805,000
TOTAL NET PROJECT COST											$161,877,008
TOTAL NET PROJECT COST ($/kW)											$208

Note 1. TEP is responsible for 50% of the closure costs associated with the Well Field Storage Ponds (amount shown in table). The remaining 50% is the responsibility of the owners of Units 3 and 4.

① one unit 11,141,395
OHD (36%) 4,010,902
15,152,297

Black Mountain Generating Station

BMGS CT 1 and 2 - Dismantlement Estimate				
Task/Description	Quantity	Units	$/Unit	Total Cost
1. Common Facilities				
a. Pavement Removal	5,000	SY	$13.60	$68,000
b. Gravel Road Removal	2,150	SY	$1.49	$3,204
c. Crushed Rock Surfacing Removal	6,780	CY	$8.96	$60,749
d. Perimeter Fencing Removal	4,870	LF	$3.63	$17,676
e. Tank Foundations	90	CY	$81.47	$7,332
f. Pipe Rack Removal	30	Tons	$256.03	$7,681
g. Disposal				
i. Waste Hauling (10 mi haul)	2,500	Tons	$8.24	$20,600
ii. Landfill Fees	2,500	Tons	$30.45	$76,125
2. Building Removal				
a. Building Removal	199,390	CF	$0.33	$66,799
b. Building Foundation Removal	310	CY	$81.47	$25,256
c. Disposal				
i. Waste Hauling (10 mi haul)	3,120	Tons	$8.24	$25,709
ii. Landfill Fees	3,120	Tons	$30.45	$95,004
3. Powerblock Foundation Demolition				
a. LM 6000 (Quantity 2)	630	CY	$81.47	$51,326
b. Transformer Foundations	230	CY	$81.47	$18,736
c. Miscellaneous Foundations	180	CY	$81.47	$14,665
d. Disposal				
i. Waste Hauling (10 mi haul)	2,100	Tons	$8.24	$17,304
ii. Landfill Fees	2,100	Tons	$30.45	$63,945
4. Major Equipment Removal				
a. LM 6000 (Quantity 2)	680	Tons	$256.03	$174,100
b. Piping	70	Tons	$256.03	$17,922
c. Chiller / Cooling Tower	150	Tons	$256.03	$38,405
d. Misc. Equipment	24,290	lbs	$0.13	$3,158
e. Steel Tanks	310	CF	$63.73	$19,756
f. Plastic Tanks	100	CF	$47.05	$4,705
g. Disposal				
i. Waste Hauling (10 mi haul)	310	Tons	$8.24	$2,554
ii. Landfill Fees	310	Tons	$30.45	$9,440
5. Plant Electrical systems				
a. Transformer Removal	246,710	lbs	$0.13	$32,072
b. Switchgear/MCC Removal	81,730	lbs	$0.13	$10,625
c. Concrete Ductbank Demolition	-	CY	-	-
d. Misc. Electrical Foundation Demolition	50	CF	$3.02	$151
e. Misc. Wiring Demolition	190	lbs	$2.57	$488
f. Disposal				
i. Waste Hauling (10 mi haul)	210	Tons	$8.24	$1,730
ii. Landfill Fees	210	Tons	$30.45	$6,395
6. Miscellaneous				
a. Well Removal	2	Wells	$13,000.00	$26,000
7. Site Restoration Costs				
a. Earthwork	95,050	SY	$0.99	$94,100
b. Seeding	95,050	SY	$0.52	$49,425
8. Environmental Cleanup				$351,048
a. Pond Closure				n/a
b. ACM Removal/Disposal				n/a
c. PCB Disposal				n/a
d. Refractory Disposal				n/a
e. Mercury Disposal				n/a
f. Fuel Oil Tank Soil Disposal				n/a
g. Nuclear Device Disposal				
9. Scrap Value				
a. Steel				
i. LM6000 (Quantity 2)	371	Tons	($165.00)	($61,215)
ii. Pipe Rack Steel	27	Tons	($165.00)	($4,505)
iii. Piping - Steel	45	Tons	($165.00)	($7,376)
iv. Piping - Stainless	8	Tons	($225.00)	($1,688)
v. Cooling Tower	120	Tons	($165.00)	($19,800)
vi. Transformers	60	lbs	($165.00)	($9,900)
vii. Motors	3,470	lbs	($0.08)	($278)
viii. Steel Tanks	310	CF	($40.43)	($12,533)
b. Copper				
i. Generators	45	Tons	($2,290.00)	($104,424)
ii. Transformers	8	Tons	($2,280.00)	($17,884)
iii. Motors	1,490	lbs	($1.15)	($1,714)
c. Misc. Equipment - Steel	15,440	lbs	($0.08)	($1,235)
TOTAL COST				$1,481,098
PROJECT INDIRECTS				
a. Contractor Indirects 5% of Total Cost				$74,000
b. Engineering				$44,000
c. Construction Management				$30,000
d. Owner Indirects				$59,000
e. Performance Bond				$30,000
CONTINGENCY (20%)				$296,000
TOTAL SCRAP CREDIT				($243,000)
TOTAL NET PROJECT COST				$1,771,000
TOTAL NET PROJECT COST ($/kW)				$20.90

Valencia Power Plant

VPP CT 1, 2, 3, and 4 - Dismantlement Estimate				
Task/Description	**Quantity**	**Units**	**$/Unit**	**Total Cost**
1. Common Facilities				
a. Paving Removal	5,290	SY	$13.60	$71,944
b. Crushed Rock Surfacing Removal	580	CY	$8.15	$4,562
c. Perimeter Fencing Removal	1,400	LF	$3.30	$4,622
d. Tank Foundations	560	CY	$81.47	$45,623
e. Disposal				
i. Waste Hauling (10 mi haul)	3,700	Tons	$6.24	$23,076
ii. Landfill Fees	3,700	Tons	$30.45	$112,665
2. Building Removal				
a. Building Removal	155,850	CF	$0.30	$46,330
b. Building Foundation Removal	650	CY	$81.47	$52,956
c Disposal				
i. Waste Hauling (10 mi haul)	5,210	Tons	$6.24	$32,497
ii. Landfill Fees	5,210	Tons	$30.45	$158,645
3. Powerblock Foundation Demolition				
a. LM 2500 (Quantity 1)	190	CY	$81.47	$15,479
b. Hitachi Frame 5 (Quantity 3)	710	CY	$81.47	$57,844
c. Transformer Foundations	50	CY	$81.47	$4,074
d. Substation Foundations	120	CY	$81.47	$9,776
e Miscellaneous Foundations	40	CY	$81.47	$3,259
f. Disposal				
i. Waste Hauling (10 mi haul)	2,230	Tons	$6.24	$13,909
ii. Landfill Fees	2,230	Tons	$30.45	$67,904
4. Major Equipment Removal				
a. LM 2500 Removal (Quantity 1)	120	Tons	$232.76	$27,931
b. Hitachi Removal (Quantity 3)	480	Tons	$232.76	$111,724
c. Piping	4	Tons	$232.76	$997
d. Misc. Equipment	18	Tons	$232.76	$4,144
e. Steel Tanks	160	CF	$57.03	$9,124
f. Plastic Tanks	200	CF	$42.77	$8,554
g. Disposal				
i. Waste Hauling (10 mi haul)	270	Tons	$6.24	$1,684
ii. Landfill Fees	270	Tons	$30.45	$8,222
5. Plant Electrical systems				
a. Transformer Removal	150	Tons	$232.76	$34,914
b. Switchgear/MCC Removal	40	Tons	$232.76	$9,310
c. Concrete Ductbank Demolition	110	CY	$81.47	$8,962
d. Miscellaneous Wiring Demolition	190	CF	$2.34	$444
e. Reactor Demolition	2,160	lbs	$0.12	$251
f. Disposal				
i. Waste Hauling (10 mi haul)	340	Tons	$6.24	$2,121
ii. Landfill Fees	340	Tons	$30.45	$10,353
6. Miscellaneous				
a. Well Removal	-	Wells	-	-
7. Site Restoration Costs				
a. Earthwork	2	Acres	$4,347.03	$8,578
b. Seeding	2	Acres	$2,537.50	$5,024
8. Environmental Cleanup				
a. Pond Closure				n/a
b. ACM Removal/Disposal				n/a
c. PCB Disposal				n/a
d. Refractory Disposal				n/a
e. Mercury Disposal				$11,270
f. Fuel Oil Tank Soil Disposal				$19,936
g. Nuclear Device Disposal				n/a
9. Scrap Value				
a. Steel				
i. LM2500 (Quantity 1)	68	Tons	($165.00)	($11,220)
ii Hitachi Frame 5 (Quantity 3)	325	Tons	($165.00)	($53,626)
iii. Piping - Steel	2	Tons	($165.00)	($248)
iv. Piping - Stainless	1	Tons	($222.50)	($312)
v. Transformers	70	Tons	($165.00)	($11,550)
vi. Motors	450	lbs	($0.08)	($37)
vi. Steel Tanks	160	CF	($40.43)	($6,468)
b. Copper				
i. Generators	53	Tons	($2,290.00)	($121,370)
ii. Transformers	15	Tons	($2,290.00)	($33,958)
iii. Motors	190	lbs	($1.15)	($218)
c. Equipment - Steel	27,870	lbs	($0.08)	($2,299)
TOTAL COST				**$1,011,880**
PROJECT INDIRECTS				
a. Contractor Indirects 5% of Total Cost				$51,000
b. Engineering				$30,000
c. Construction Management				$20,000
d. Owner Indirects				$40,000
e. Performance Bond				$20,000
CONTINGENCY (20%)				$202,000
TOTAL SCRAP CREDIT				($241,880)
TOTAL NET PROJECT COST				**$1,133,000**
TOTAL NET PROJECT COST ($/kW)				**$17.00**

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DeMoss Petrie Generating Station

DPGS CT 1 - Dismantlement Estimate				
Task/Description	Quantity	Units	$/Unit	Total Cost
1. Common Facilities				
a. Pavement Removal	-	SY	-	-
b. Gravel Road Removal	1,516	SY	$1.36	$2,051
c. Crushed Rock Surfacing Removal	1,650	CY	$8.15	$13,523
d. Perimeter Fencing Removal	1,280	LF	$3.30	$4,160
e. Tank Foundations	20	CY	$81.47	$1,629
f. Disposal				
i. Waste Hauling (10 mi haul)	3,140	Tons	$6.24	$19,585
ii. Landfill Fees	3,140	Tons	$30.45	$95,613
2. Building Removal				
a. Building Removal	67,280	CF	$0.30	$20,001
b. Building Foundation Removal	100	CY	$81.47	$8,147
c. Disposal				
i. Waste Hauling (10 mi haul)	1,890	Tons	$6.24	$11,789
ii. Landfill Fees	1,890	Tons	$30.45	$57,551
3. Powerblock Foundation Demolition				
a. TEA (Quantity 1)	420	CY	$81.47	$34,217
b. Transformer Foundations	40	CY	$81.47	$3,258
c. Miscellaneous Foundations	900	CY	$81.47	$73,323
d. Disposal				
i. Waste Hauling (10 mi haul)	2,740	Tons	$6.24	$17,090
ii. Landfill Fees	2,740	Tons	$30.45	$83,433
4. Major Equipment Removal				
a. TEA Removal (Quantity 1)	934	Tons	$232.76	$217,490
b. Piping	21	Tons	$232.76	$4,626
c. Misc. Equipment	7	Tons	$232.76	$1,599
d. Steel Tanks	750	CF	$57.03	$42,769
e. Plastic Tanks	10	CF	$42.77	$428
f. Disposal				
i. Waste Hauling (10 mi haul)	220	Tons	$6.24	$1,372
ii. Landfill Fees	220	Tons	$30.45	$6,699
5. Plant Electrical systems				
a. Transformer Removal	241,950	lbs	$0.12	$28,159
b. Switchgear/MCC Removal	39,000	lbs	$0.12	$4,539
c. Concrete Ductbank Demolition	647,400	lbs	$0.02	$12,948
d. Miscellaneous Wiring Demolition	50	CF	$2.34	$117
e. Disposal				
i. Waste Hauling (10 mi haul)	396	Tons	$6.24	$2,471
ii. Landfill Fees	396	Tons	$30.45	$12,065
6. Miscellaneous				
a. Well Removal	2	Wells	$13,000	$26,000
7. Site Restoration Costs				
a. Earthwork	2	Acres	$4,347.03	$9,868
b. Seeding	2	Acres	$2,537.50	$5,760
8. Environmental Cleanup				
a. Pond Closure				n/a
b. ACM Removal/Disposal				n/a
c. PCB Disposal				n/a
d. Refractory Disposal				n/a
e. Mercury Disposal				$11,270
f. Fuel Oil Tank Soil Disposal				$456,330
g. Nuclear Device Disposal				n/a
9. Scrap Value				
a. Steel				
i. TEA (Quantity 1)	700	Tons	($165)	($115,500)
ii. Piping	15	Tons	($165)	($2,488)
iii. Transformers	55	Tons	($165)	($9,074)
iv. Steel Tanks	750	CF	($40.43)	($30,319)
b. Copper				
i. Generators	23	Tons	($2,290)	($51,983)
ii. Transformers	13	Tons	($2,290)	($29,662)
iii. Motors	1	Tons	($2,290)	($1,424)
c. Equipment - Steel	2	Tons	($165)	($274)
TOTAL COST				$1,290,000
PROJECT INDIRECTS				
a. Contractor Indirects 5% of Total Cost				$65,000
b. Engineering				$39,000
c. Construction Management				$26,000
d. Owner Indirects				$52,000
e. Performance Bond				$25,000
CONTINGENCY (20%)				$258,000
TOTAL SCRAP CREDIT				($241,000)
TOTAL NET PROJECT COST				$1,515,000
TOTAL NET PROJECT COST ($/kW)				$20.00

North Loop Generating Station

NLGS CT 1, 2, 3, and 4 - Dismantlement Estimate				
Task/Description	Quantity	Units	$/Unit	Total Cost
1. Common Facilities				
a. Pavement Removal	13,170	SY	$13.69	$179,112
b. Crushed Rock Surfacing Removal	110	CY	$8.15	$896
c. Perimeter Fencing Removal	2,530	LF	$3.30	$8,650
d. Tank Foundations	990	CY	$81.47	$80,655
e. Disposal				
i. Waste Hauling (10 mi haul)	8,320	Tons	$8.24	$39,420
ii. Landfill Fees	6,320	Tons	$30.45	$192,444
2. Building Removal				
a. Building Removal	22,810	CF	$0.30	$6,781
b. Building Foundation Removal	190	CY	$81.47	$15,479
c. Disposal				
i. Waste Hauling (10 mi haul)	960	Tons	$8.24	$5,988
ii. Landfill Fees	950	Tons	$30.45	$29,232
3. Powerblock Foundation Demolition				
a. LM 2500 (Quantity 1)	420	CY	$81.47	$34,217
b. Westinghouse 251 (Quantity 3)	1,140	CY	$81.47	$92,876
c. Transformer Foundations	150	CY	$81.47	$12,221
d. Transformer Brick Wall Demo	120	CY	$81.47	$9,776
e. Miscellaneous Foundations	20	CY	$81.47	$1,629
f. Disposal				
i. Waste Hauling (10 mi haul)	3,760	Tons	$8.24	$23,452
ii. Landfill Fees	3,760	Tons	$30.45	$114,492
4. Major Equipment Removal				
a. LM 2500 Removal (Quantity 1)	140	Tons	$232.78	$32,589
b. Westinghouse 251 Removal (Quantity 3)	1,500	Tons	$232.78	$349,138
c. Piping	40	Tons	$232.78	$9,310
d. Misc. Equipment	2	Tons	$232.78	$466
e. Steel Tanks	970	CF	$57.03	$55,315
f. Plastic Tanks	20	CF	$42.77	$855
g. Disposal				
i. Waste Hauling (10 mi haul)	850	Tons	$8.24	$4,054
ii. Landfill Fees	650	Tons	$30.45	$19,799
5. Plant Electrical systems				
a. Transformer Removal	356,150	lbs	$0.12	$41,332
b. Switchgear/MCC Removal	118,500	lbs	$0.12	$13,791
c. Concrete Ductbank Demolition	80	CY	$81.47	$6,888
d. Miscellaneous Wiring Demolition	190	CF	$2.34	$444
e. Reactor Demolition	8,620	lbs	$0.12	$1,003
f. Disposal				
i. Waste Hauling (10 mi haul)	250	Tons	$8.24	$1,559
ii. Landfill Fees	250	Tons	$30.45	$7,613
6. Miscellaneous				
a. Well Removal	1	Well	$13,000.00	$13,000
7. Site Restoration Costs				
a. Earthwork	25,760	SY	$0.90	$23,136
b. Seeding	25,760	SY	$0.52	$13,505
8. Environmental Cleanup				
a. Pond Closure				n/a
b. ACM Removal/Disposal				n/a
c. PCB Disposal				n/a
d. Refractory Disposal				n/a
e. Mercury Disposal				$11,270
f. Fuel Oil Tank Soil Disposal				$455,330
g. Nuclear Device Disposal				n/a
9. Scrap Value				
a. Steel				
i. LM2500 (Quantity 1)	80	Tons	($165.00)	($13,200)
ii. Westinghouse 251 (Quantity 3)	850	Tons	($165.00)	($140,250)
iii. Piping - Steel	23	Tons	($165.00)	($3,795)
iv. Piping - Stainless	1	Tons	($222.50)	($312)
v. Transformers	181,430	lbs	($0.08)	($13,318)
vi. Motors	1,110	lbs	($0.08)	($89)
vii. Steel Tanks	970	CF	($40.43)	($39,212)
b. Copper				
i. Generators	82	Tons	($2,280.00)	($187,780)
ii. Transformers	44,900	lbs	($1.15)	($51,411)
iii. Motors	480	lbs	($1.15)	($550)
c. Equipment - Steel	2,070	lbs	($0.08)	($171)
TOTAL COST				$1,997,900
PROJECT INDIRECTS				
a. Contractor Indirects 5% of Total Cost				$95,000
b. Engineering				$57,000
c. Construction Management				$38,000
d. Owner Indirects				$76,000
e. Performance Bond				$38,000
CONTINGENCY (20%)				$381,000
TOTAL SCRAP CREDIT				($450,000)
TOTAL NET PROJECT COST				$2,142,000
TOTAL NET PROJECT COST ($/kW)				$23.00

APPENDIX B – SITE LAYOUT DRAWINGS

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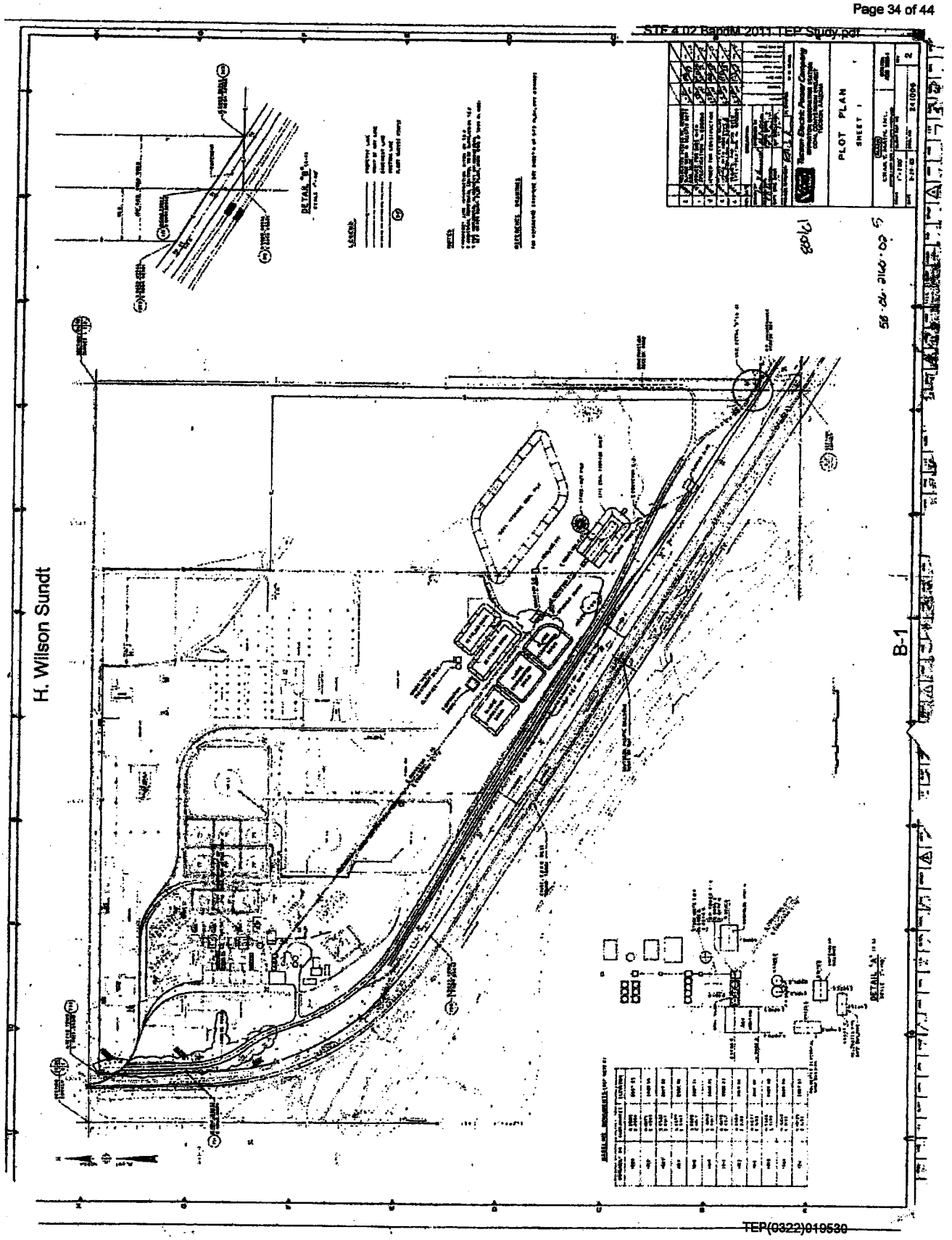

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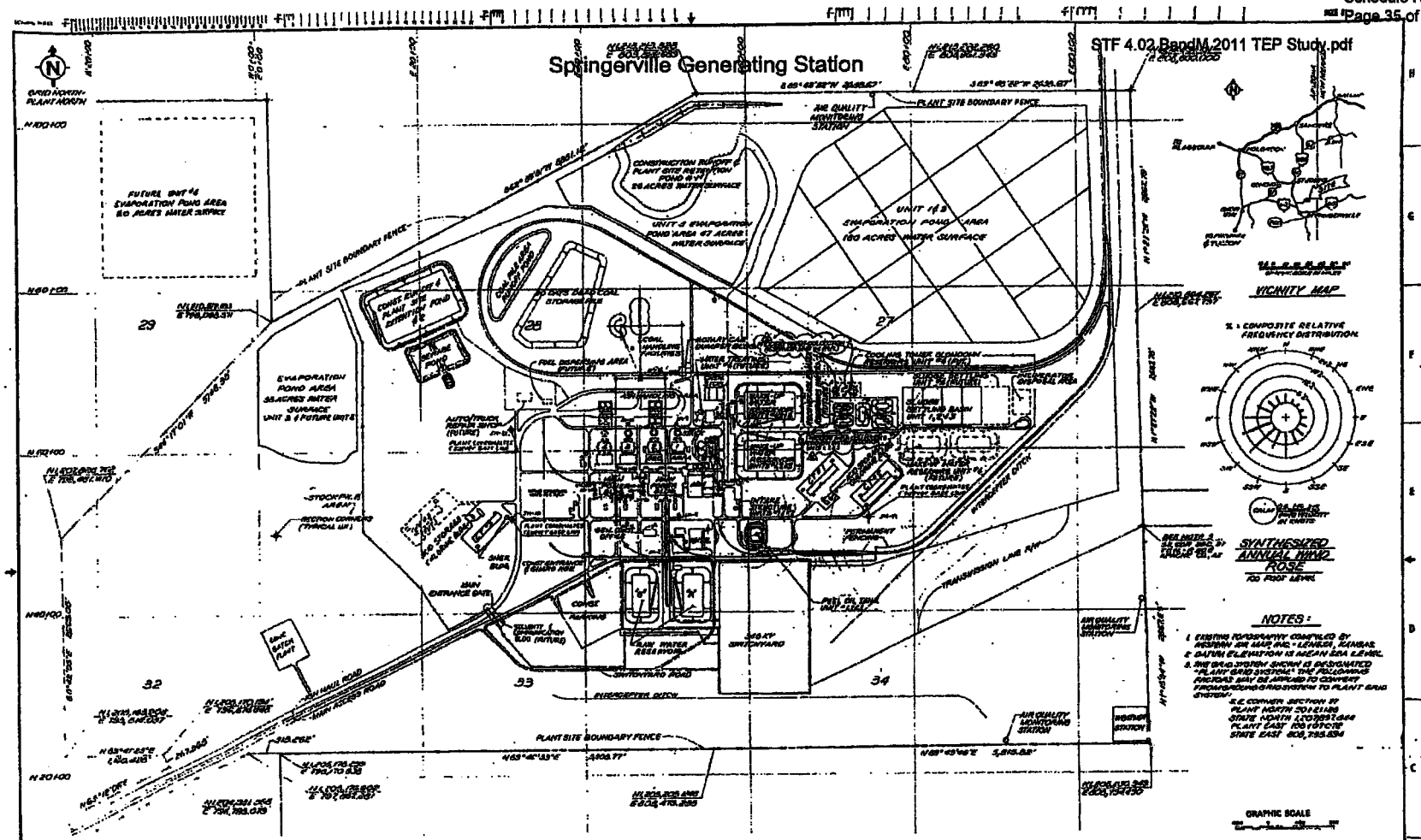

UNIT 3 JOB MONUMENT SCHEDULE			
JOB - NUMBER	NORTH COORDINATE	EAST COORDINATE	ELEVATION
JM-14	66+00.00	41+00.00	6974.79
JM-15	59+00.00	47+00.00	6974.34
JM-16	52+00.00	53+00.00	6974.19
JM-17	45+00.00	59+00.00	6974.32
JM-18	38+00.00	65+00.00	6974.27
JM-19	31+00.00	71+00.00	—
JM-20	24+00.00	77+00.00	—
JM-21	17+00.00	83+00.00	—

JOB MONUMENT SCHEDULE			
JM - NUMBER	NORTH COORDINATE	EAST COORDINATE	ELEVATION
JM-1	50+34.91	54+58.03	6975.59
JM-2	51+84.91	51+49.00	6974.34
JM-3	50+00.00	50+37.13	—
JM-4	45+00.00	45+00.00	6974.19
JM-5	40+00.00	40+00.00	6974.34
JM-6	35+00.00	35+00.00	6974.19
JM-7	30+00.00	30+00.00	6974.32
JM-8	25+00.00	25+00.00	6974.27
JM-9	20+00.00	20+00.00	—
JM-10	15+00.00	15+00.00	—
JM-11	10+00.00	10+00.00	—
JM-12	5+00.00	5+00.00	6975.00

BECHTEL
LOS ANGELES
SPRINGERVILLE GENERATING STATION
TUCSON ELECTRIC POWER COMPANY
SITE PLAN AND VICINITY LOCATION PLAN

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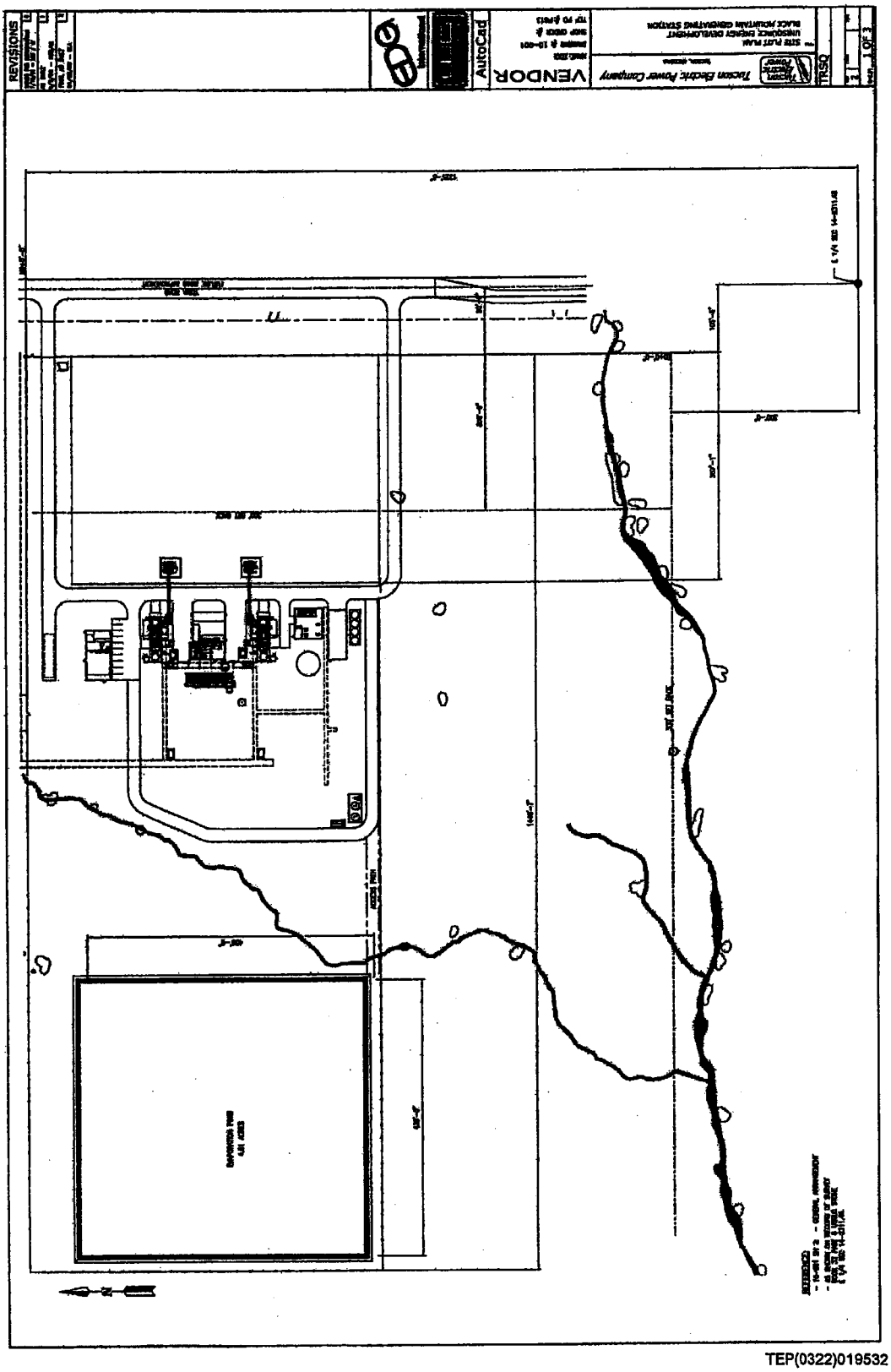

Black Mountain Generating Station

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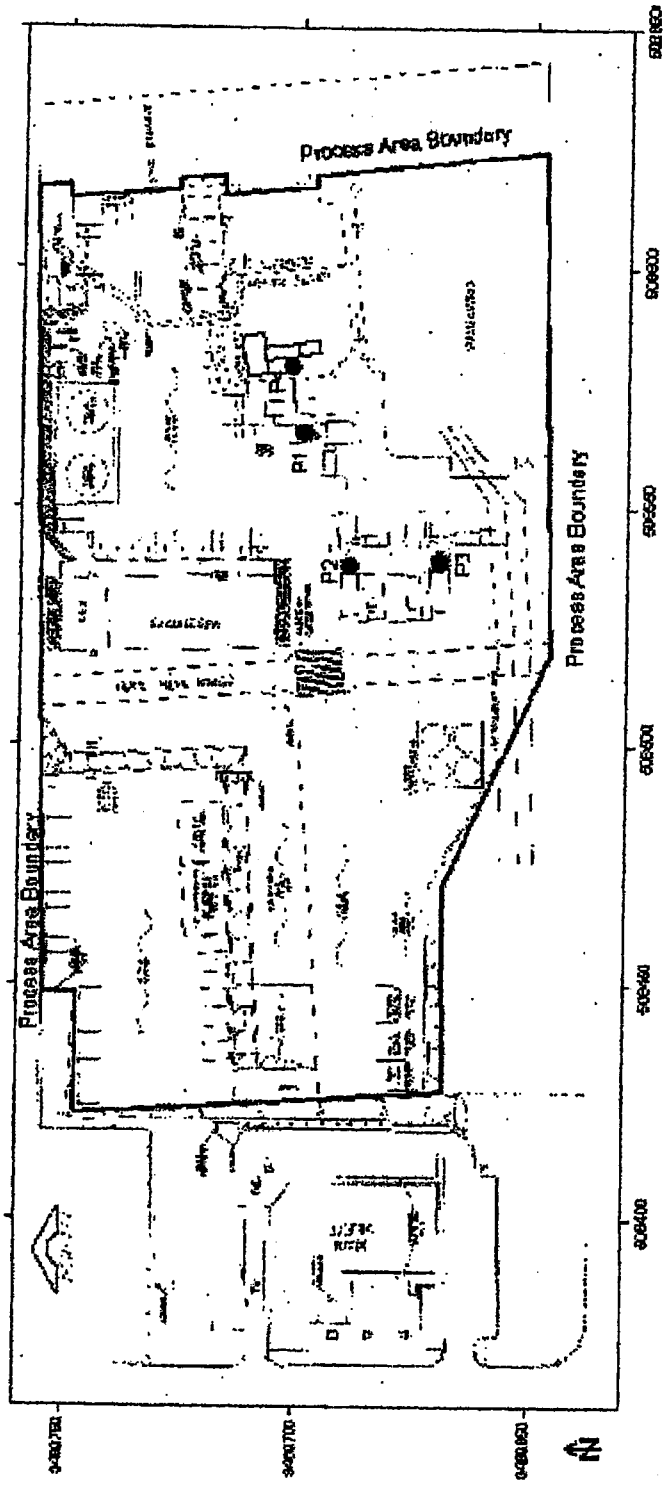
Valencia Power Plant



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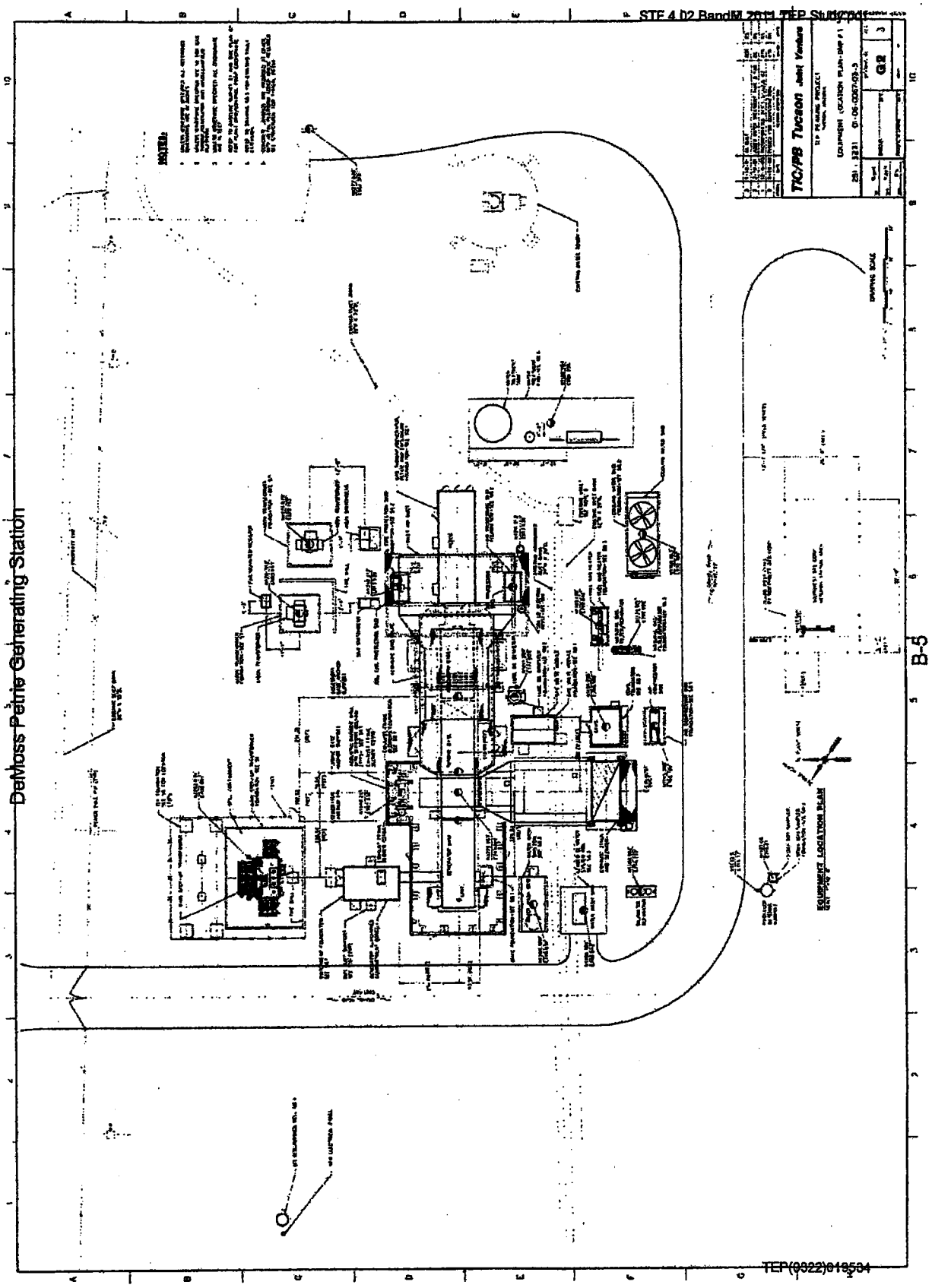

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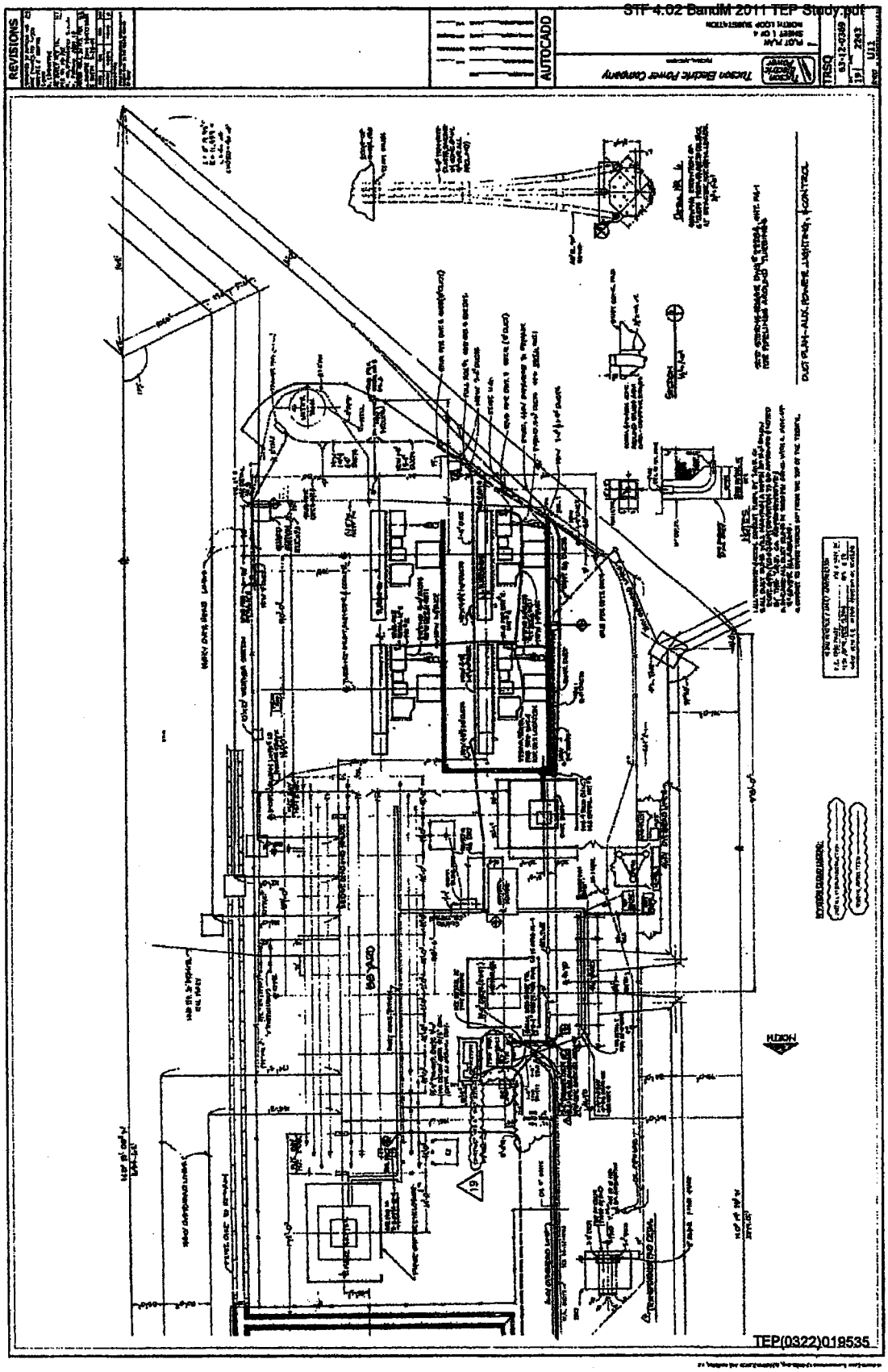

North Loop Generating Station

APPENDIX C – POND/LANDFILL DECOMMISSIONING COST ESTIMATES

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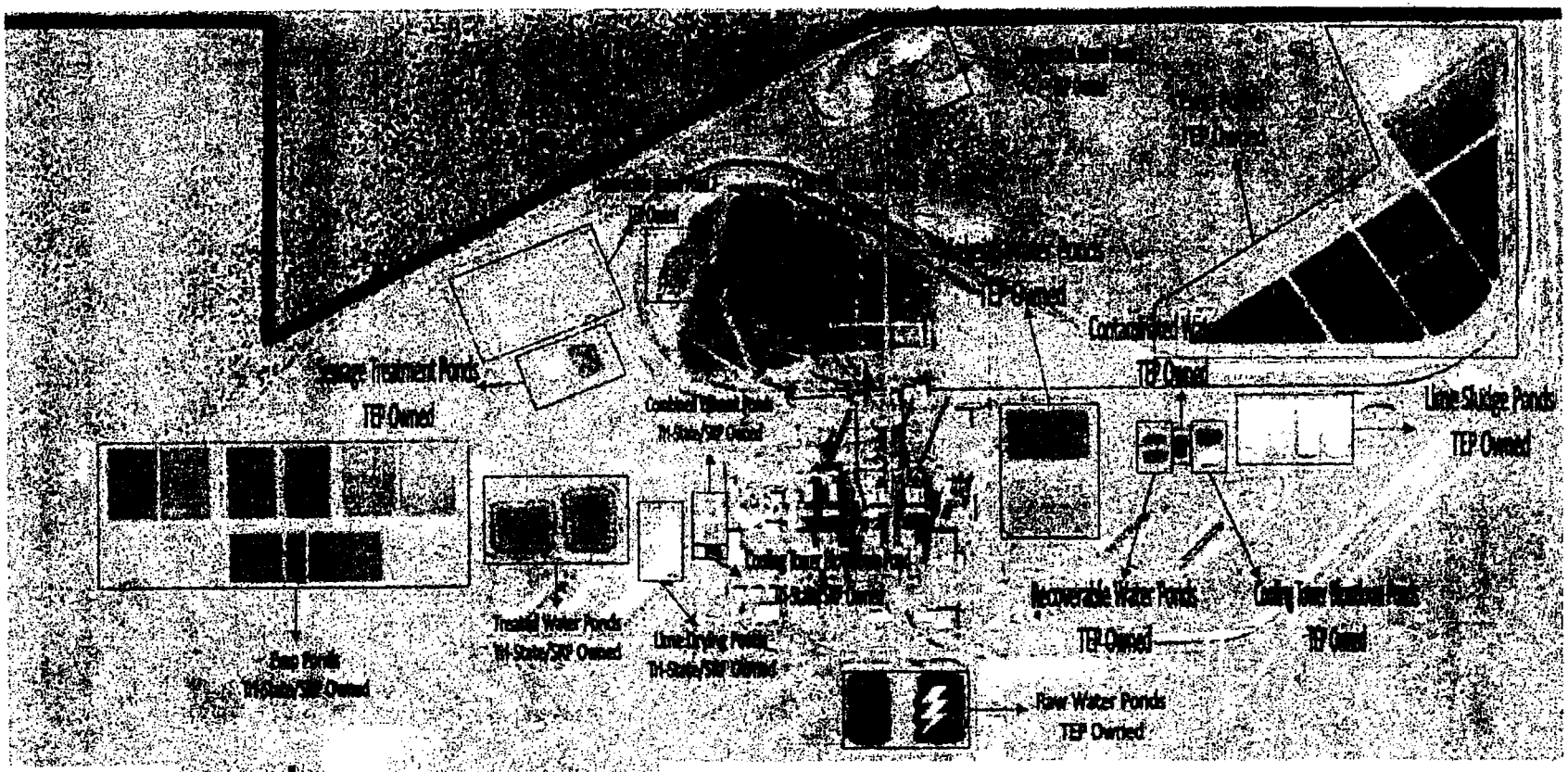
HWS Units 1, 2, 3, and 4 and CT 1 and 2 - Pond/Coal Pile Area Estimate

Description	Closure Approach	Area (ft^2)	Area (acres)	Depth (ft)	Perimeter (ft)	Height (ft)	Top Berm Width (ft)	Bottom Berm Width (ft)	Berm Volume (ft^3)	Berm Volume (yd^3)	Closure Cap	Berm Grading	Total Cost
Coal Pile Area	Remove 12-inch layer, offsite transport & disposal (special waste), 12-inch fill, rough grading, 6-inch topsoil, fine grading, hydroseed	845,454	19.4								$ 3,872,892		$ 3,872,892
Evaporation Ponds	Grade berms, rough grading, 6-inch topsoil layer, fine grading, hydroseed	190,110	4.4	15	2,188	15	10	25	574,350	21,272	$ 233,775	$ 106,361	$ 340,136
Process Water Ponds	Rough grading, 40-mil HDPE geomembrane, geo-net drainage layer, 12-inch rooting layer soil, 6-inch topsoil layer, fine grading, hydroseed	137,721	3.2								$ 490,174		$ 490,174
TOTAL COST ($)													$ 4,703,202

SGS Units 1 and 2 - Pond/Coal Pile Area/Landfill Estimate

Description	Number of Ponds/ Areas	Closure Approach	Area (ft^2)	Area (acres)	Depth (ft)	Perimeter (ft)	Height (ft)	Top Berm Width (ft)	Bottom Berm Width (ft)	Berm Volume (ft^3)	Berm Volume (yd^3)	Closure Cap	Berm Grading	Total Cost
Coal Pile Area	1	Remove 12-inch layer, offsite transport & disposal (special waste), 12-inch fill, rough grading, 6-inch topsoil, fine grading, hydroseed	2,570,327	59.0								$ 11,774,263		$ 11,774,263
Coal Pile Run-Off Pond	1	Grade berms, rough grading, 6-inch topsoil layer, fine grading, hydroseed	714,841	16.4	15	3,754	15	10	30	1,126,200	41,711	$ 879,028	$ 206,556	$ 1,067,584
Evaporation Ponds	6	Grade berms, rough grading, 6-inch topsoil layer, fine grading, hydroseed	3,631,530	83.4	15	10,131	15	10	30	3,039,300	112,567	$ 4,465,631	$ 562,833	$ 5,028,464
Process Water Ponds	5	Rough grading, 40-mil HDPE geomembrane, geo-net drainage layer, 12-inch rooting layer soil, 6-inch topsoil layer, fine grading, hydroseed	524,356	12.0								$ 1,866,288		$ 1,866,288
Sludge Ponds	4	Rough grading, 40-mil HDPE geomembrane, geo-net drainage layer, 12-inch rooting layer soil, 6-inch topsoil layer, fine grading, hydroseed	282,347	6.5								$ 1,004,925		$ 1,004,925
Make-Up Water Ponds	2	Grade berms, rough grading, 6-inch topsoil layer, fine grading, hydroseed	852,819	19.6	15	3,866	15	10	30	1,165,800	43,178	$ 1,048,697	$ 215,869	$ 1,264,566
Raw Water Storage Ponds	2	Grade berms, rough grading, 6-inch topsoil layer, fine grading, hydroseed	824,909	18.9	15	3,800	15	10	30	1,140,000	42,222	$ 1,014,377	$ 211,111	$ 1,225,488
Sewage Ponds	2	Rough grading, 40-mil HDPE geomembrane, geo-net drainage layer, 12-inch rooting layer soil, 6-inch topsoil layer, fine grading, hydroseed	194,149	4.5								$ 691,012		$ 691,012
Construction Run-Off Pond #1 (North of Coal Yard)	1	Grade berms, rough grading, 6-inch topsoil layer, fine grading, hydroseed	675,000	15.5	15	2,819	15	10	30	845,700	31,322	$ 830,036	$ 156,611	$ 986,647
Construction Run-Off Pond #2 (North of Sewage Ponds)	1	Grade berms, rough grading, 6-inch topsoil layer, fine grading, hydroseed	640,662	14.7	15	3,445	15	10	30	1,033,500	38,278	$ 787,811	$ 191,389	$ 979,200
Well Field Storage Ponds[1]	2	Grade berms, rough grading, 6-inch topsoil layer, fine grading, hydroseed	217,564	5.0	15	2,285	15	10	30	685,500	25,389	$ 267,535	$ 126,944	$ 197,240
Ash Landfill	1	Rough grading, 40-mil HDPE geomembrane, geo-net drainage layer, 12-inch rooting layer soil, 6-inch topsoil layer, fine grading, hydroseed	12,935,883	297.0								$ 46,041,171		$ 46,041,171
TOTAL COST ($)														$ 72,146,979

Note 1. TEP is responsible for 50% of the closure costs associated with the Well Field Storage Ponds (amount shown in table). The remaining 50% is the responsibility of the owners of Units 3 and 4.
Note 2 An SGS pond ownership map is included on page C-3. The map provides pond location and ownership information.



Springerville Generating Station
Pond Ownership
December 1, 2011

Tucson Electric Power
A UniSource Energy Company

C-3

TEP(0322)019539

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STF 4.02 BandM 2011 TEP Study.pdf

BMGS CT 1 and 2 - Pond Estimate													
Description	Closure Approach	Area (ft^2)	Area (acres)	Depth (ft)	Perimeter (ft)	Height (ft)	Top Berm Width (ft)	Bottom Berm Width (ft)	Berm Volume (ft^3)	Berm Volume (yd^3)	Closure Cap	Berm Grading	Total Cost
Evaporation Pond	Grade berms, rough grading, 6-inch topsoil layer, fine grading, hydroseed	200,000	4.6	15	1,892	15	10	30	567,600	21,022	$ 245,937	$ 105,111	$ 351,048
TOTAL COST ($)													$ 351,048

CPI Detailed Report
Data for March 2016

Editors
Malik Crawford
Jonathan Church
Bradley Akin

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Table 24. Historical Consumer Price Index for All Urban Consumers (CPI-U): U. S. city average, all items

(1982-84=100, unless otherwise noted)

Year	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
1913	9.8	9.8	9.8	9.8	9.7	9.8	9.9	9.9	10.0	10.0	10.1	10.0
1914	10.0	9.9	9.9	9.8	9.9	9.9	10.0	10.2	10.2	10.1	10.2	10.1
1915	10.1	10.0	9.9	10.0	10.1	10.1	10.1	10.1	10.1	10.2	10.3	10.3
1916	10.4	10.4	10.5	10.6	10.7	10.8	10.8	10.9	11.1	11.3	11.5	11.6
1917	11.7	12.0	12.0	12.6	12.8	13.0	12.8	13.0	13.3	13.5	13.5	13.7
1918	14.0	14.1	14.0	14.2	14.5	14.7	15.1	15.4	15.7	16.0	16.3	16.5
1919	16.5	16.2	16.4	16.7	16.9	16.9	17.4	17.7	17.8	18.1	18.5	18.9
1920	19.3	19.5	19.7	20.3	20.6	20.9	20.8	20.3	20.0	19.9	19.8	19.4
1921	19.0	18.4	18.3	18.1	17.7	17.6	17.7	17.7	17.5	17.5	17.4	17.3
1922	16.9	16.9	16.7	16.7	16.7	16.7	16.8	16.8	16.6	16.7	16.8	16.9
1923	16.8	16.8	16.8	16.9	16.9	17.0	17.2	17.1	17.2	17.3	17.3	17.3
1924	17.3	17.2	17.1	17.0	17.0	17.0	17.1	17.0	17.1	17.2	17.2	17.3
1925	17.3	17.2	17.3	17.2	17.3	17.5	17.7	17.7	17.7	17.7	18.0	17.9
1926	17.9	17.9	17.8	17.9	17.8	17.7	17.5	17.4	17.5	17.6	17.7	17.7
1927	17.5	17.4	17.3	17.3	17.4	17.6	17.3	17.2	17.3	17.4	17.3	17.3
1928	17.3	17.1	17.1	17.1	17.2	17.1	17.1	17.1	17.3	17.2	17.2	17.1
1929	17.1	17.1	17.0	16.9	17.0	17.1	17.3	17.3	17.3	17.3	17.3	17.2
1930	17.1	17.0	16.9	17.0	16.9	16.8	16.6	16.5	16.6	16.5	16.4	16.1
1931	15.9	15.7	15.6	15.5	15.3	15.1	15.1	15.1	15.0	14.9	14.7	14.6
1932	14.3	14.1	14.0	13.9	13.7	13.6	13.6	13.5	13.4	13.3	13.2	13.1
1933	12.9	12.7	12.6	12.6	12.6	12.7	13.1	13.2	13.2	13.2	13.2	13.2
1934	13.2	13.3	13.3	13.3	13.3	13.4	13.4	13.4	13.6	13.5	13.5	13.4
1935	13.6	13.7	13.7	13.8	13.8	13.7	13.7	13.7	13.7	13.7	13.8	13.8
1936	13.8	13.8	13.7	13.7	13.7	13.8	13.9	14.0	14.0	14.0	14.0	14.0
1937	14.1	14.1	14.2	14.3	14.4	14.4	14.5	14.5	14.6	14.6	14.5	14.4
1938	14.2	14.1	14.1	14.2	14.1	14.1	14.1	14.1	14.1	14.0	14.0	14.0
1939	14.0	13.9	13.9	13.8	13.8	13.8	13.8	13.8	14.1	14.0	14.0	14.0
1940	13.9	14.0	14.0	14.0	14.0	14.1	14.0	14.0	14.0	14.0	14.0	14.1
1941	14.1	14.1	14.2	14.3	14.4	14.7	14.7	14.9	15.1	15.3	15.4	15.5
1942	15.7	15.8	16.0	16.1	16.3	16.3	16.4	16.5	16.5	16.7	16.8	16.9
1943	16.9	16.9	17.2	17.4	17.5	17.5	17.4	17.3	17.4	17.4	17.4	17.4
1944	17.4	17.4	17.4	17.5	17.5	17.8	17.7	17.7	17.7	17.7	17.7	17.8
1945	17.8	17.8	17.8	17.8	17.9	18.1	18.1	18.1	18.1	18.1	18.1	18.2
1946	18.2	18.1	18.3	18.4	18.5	18.7	19.8	20.2	20.4	20.8	21.3	21.5
1947	21.5	21.5	21.9	21.9	21.9	22.0	22.2	22.5	23.0	23.0	23.1	23.4
1948	23.7	23.5	23.4	23.8	23.9	24.1	24.4	24.5	24.5	24.4	24.2	24.1
1949	24.0	23.8	23.8	23.9	23.8	23.9	23.7	23.8	23.9	23.7	23.8	23.6
1950	23.5	23.5	23.6	23.6	23.7	23.8	24.1	24.3	24.4	24.6	24.7	25.0
1951	25.4	25.7	25.8	25.8	25.9	25.9	25.9	25.9	26.1	26.2	26.4	26.5
1952	26.5	26.3	26.3	26.4	26.4	26.5	26.7	26.7	26.7	26.7	26.7	26.7
1953	26.6	26.5	26.6	26.6	26.7	26.8	26.8	26.9	26.9	27.0	26.9	26.9
1954	26.9	26.9	26.9	26.8	26.9	26.9	26.9	26.9	26.8	26.8	26.8	26.7
1955	26.7	26.7	26.7	26.7	26.7	26.7	26.8	26.8	26.9	26.9	26.9	26.8
1956	26.8	26.8	26.8	26.9	27.0	27.2	27.4	27.3	27.4	27.5	27.5	27.6
1957	27.6	27.7	27.8	27.9	28.0	28.1	28.3	28.3	28.3	28.3	28.4	28.4
1958	28.6	28.6	28.8	28.9	28.9	28.9	29.0	28.9	28.9	28.9	29.0	28.9
1959	29.0	28.9	28.9	29.0	29.0	29.1	29.2	29.2	29.3	29.4	29.4	29.4
1960	29.3	29.4	29.4	29.5	29.5	29.6	29.6	29.6	29.6	29.8	29.8	29.8
1961	29.8	29.8	29.8	29.8	29.8	29.8	30.0	29.9	30.0	30.0	30.0	30.0
1962	30.0	30.1	30.1	30.2	30.2	30.2	30.3	30.3	30.4	30.4	30.4	30.4
1963	30.4	30.4	30.5	30.5	30.5	30.6	30.7	30.7	30.7	30.8	30.8	30.9
1964	30.9	30.9	30.9	30.9	30.9	31.0	31.1	31.0	31.1	31.1	31.2	31.2
1965	31.2	31.2	31.3	31.4	31.4	31.6	31.6	31.6	31.6	31.7	31.7	31.8
1966	31.8	32.0	32.1	32.3	32.3	32.4	32.5	32.7	32.7	32.9	32.9	32.9
1967	32.9	32.9	33.0	33.1	33.2	33.3	33.4	33.5	33.6	33.7	33.8	33.9
1968	34.1	34.2	34.3	34.4	34.5	34.7	34.9	35.0	35.1	35.3	35.4	35.5
1969	35.6	35.8	36.1	36.3	36.4	36.6	36.8	37.0	37.1	37.3	37.5	37.7

See footnotes at end of table.

Table 24. Historical Consumer Price Index for All Urban Consumers (CPI-U): U. S. city average, all items-Continued

(1982-84=100, unless otherwise noted)

Year	Semiannual averages		Annual avg.	Percent change from previous	
	1st half	2nd half		Dec.	Annual avg.
1913	-	-	9.9	-	-
1914	-	-	10.0	1.0	1.0
1915	-	-	10.1	2.0	1.0
1916	-	-	10.9	12.6	7.9
1917	-	-	12.8	18.1	17.4
1918	-	-	15.1	20.4	18.0
1919	-	-	17.3	14.5	14.6
1920	-	-	20.0	2.6	15.6
1921	-	-	17.9	-10.8	-10.5
1922	-	-	16.8	-2.3	-6.1
1923	-	-	17.1	2.4	1.8
1924	-	-	17.1	.0	.0
1925	-	-	17.5	3.5	2.3
1926	-	-	17.7	-1.1	1.1
1927	-	-	17.4	-2.3	-1.7
1928	-	-	17.1	-1.2	-1.7
1929	-	-	17.1	.6	.0
1930	-	-	16.7	-6.4	-2.3
1931	-	-	15.2	-9.3	-9.0
1932	-	-	13.7	-10.3	-9.9
1933	-	-	13.0	.8	-5.1
1934	-	-	13.4	1.5	3.1
1935	-	-	13.7	3.0	2.2
1936	-	-	13.9	1.4	1.5
1937	-	-	14.4	2.9	3.6
1938	-	-	14.1	-2.8	-2.1
1939	-	-	13.9	.0	-1.4
1940	-	-	14.0	.7	.7
1941	-	-	14.7	9.9	5.0
1942	-	-	16.3	9.0	10.9
1943	-	-	17.3	3.0	6.1
1944	-	-	17.6	2.3	1.7
1945	-	-	18.0	2.2	2.3
1946	-	-	19.5	18.1	8.3
1947	-	-	22.3	8.8	14.4
1948	-	-	24.1	3.0	8.1
1949	-	-	23.8	-2.1	-1.2
1950	-	-	24.1	5.9	1.3
1951	-	-	26.0	6.0	7.9
1952	-	-	26.5	.8	1.9
1953	-	-	26.7	.7	.8
1954	-	-	26.9	-.7	.7
1955	-	-	26.8	.4	-.4
1956	-	-	27.2	3.0	1.5
1957	-	-	28.1	2.9	3.3
1958	-	-	28.9	1.8	2.8
1959	-	-	29.1	1.7	.7
1960	-	-	29.6	1.4	1.7
1961	-	-	29.9	.7	1.0
1962	-	-	30.2	1.3	1.0
1963	-	-	30.6	1.6	1.3
1964	-	-	31.0	1.0	1.3
1965	-	-	31.5	1.9	1.6
1966	-	-	32.4	3.5	2.9
1967	-	-	33.4	3.0	3.1
1968	-	-	34.8	4.7	4.2
1969	-	-	36.7	6.2	5.5

See footnotes at end of table.

Table 24. Historical Consumer Price Index for All Urban Consumers (CPI-U): U. S. city average, all items-Continued

(1982-84=100, unless otherwise noted)

Year	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
1970	37.8	38.0	38.2	38.5	38.6	38.8	39.0	39.0	39.2	39.4	39.6	39.8
1971	39.8	39.9	40.0	40.1	40.3	40.6	40.7	40.8	40.8	40.9	40.9	41.1
1972	41.1	41.3	41.4	41.5	41.6	41.7	41.9	42.0	42.1	42.3	42.4	42.5
1973	42.6	42.9	43.3	43.6	43.9	44.2	44.3	45.1	45.2	45.6	45.9	46.2
1974	46.6	47.2	47.8	48.0	48.6	49.0	49.4	50.0	50.6	51.1	51.5	51.9
1975	52.1	52.5	52.7	52.9	53.2	53.6	54.2	54.3	54.6	54.9	55.3	55.5
1976	55.6	55.8	55.9	56.1	56.5	56.8	57.1	57.4	57.6	57.9	58.0	58.2
1977	58.5	59.1	59.5	60.0	60.3	60.7	61.0	61.2	61.4	61.6	61.9	62.1
1978	62.5	62.9	63.4	63.9	64.5	65.2	65.7	66.0	66.5	67.1	67.4	67.7
1979	68.3	69.1	69.8	70.6	71.5	72.3	73.1	73.8	74.6	75.2	75.9	76.7
1980	77.8	78.9	80.1	81.0	81.8	82.7	82.7	83.3	84.0	84.8	85.5	86.3
1981	87.0	87.9	88.5	89.1	89.8	90.6	91.6	92.3	93.2	93.4	93.7	94.0
1982	94.3	94.6	94.5	94.9	95.8	97.0	97.5	97.7	97.9	98.2	98.0	97.6
1983	97.8	97.9	97.9	98.6	99.2	99.5	99.9	100.2	100.7	101.0	101.2	101.3
1984	101.9	102.4	102.6	103.1	103.4	103.7	104.1	104.5	105.0	105.3	105.3	105.3
1985	105.5	106.0	106.4	106.9	107.3	107.6	107.8	108.0	108.3	108.7	109.0	109.3
1986	109.6	109.3	108.8	108.6	108.9	109.5	109.5	109.7	110.2	110.3	110.4	110.5
1987	111.2	111.6	112.1	112.7	113.1	113.5	113.8	114.4	115.0	115.3	115.4	115.4
1988	115.7	116.0	116.5	117.1	117.5	118.0	118.5	119.0	119.8	120.2	120.3	120.5
1989	121.1	121.6	122.3	123.1	123.8	124.1	124.4	124.6	125.0	125.6	125.9	126.1
1990	127.4	128.0	128.7	128.9	129.2	129.9	130.4	131.6	132.7	133.5	133.8	133.8
1991	134.6	134.8	135.0	135.2	135.6	136.0	136.2	136.6	137.2	137.4	137.8	137.9
1992	138.1	138.6	139.3	139.5	139.7	140.2	140.5	140.9	141.3	141.8	142.0	141.9
1993	142.6	143.1	143.6	144.0	144.2	144.4	144.4	144.8	145.1	145.7	145.8	145.8
1994	146.2	146.7	147.2	147.4	147.5	148.0	148.4	149.0	149.4	149.5	149.7	149.7
1995	150.3	150.9	151.4	151.9	152.2	152.5	152.5	152.9	153.2	153.7	153.6	153.5
1996	154.4	154.9	155.7	156.3	156.6	156.7	157.0	157.3	157.8	158.3	158.6	158.6
1997	159.1	159.6	160.0	160.2	160.1	160.3	160.5	160.8	161.2	161.6	161.5	161.3
1998	161.6	161.9	162.2	162.5	162.8	163.0	163.2	163.4	163.6	164.0	164.0	163.9
1999	164.3	164.5	165.0	166.2	166.2	166.2	166.7	167.1	167.9	168.2	168.3	168.3
2000	168.8	169.8	171.2	171.3	171.5	172.4	172.8	172.8	173.7	174.0	174.1	174.0
2001	175.1	175.8	176.2	176.9	177.7	178.0	177.5	177.5	178.3	177.7	177.4	176.7
2002	177.1	177.8	178.8	179.8	179.8	179.9	180.1	180.7	181.0	181.3	181.3	180.9
2003	181.7	183.1	184.2	183.8	183.5	183.7	183.9	184.6	185.2	185.0	184.5	184.3
2004	185.2	186.2	187.4	188.0	189.1	189.7	189.4	189.5	189.9	190.9	191.0	190.3
2005	190.7	191.8	193.3	194.6	194.4	194.5	195.4	196.4	198.8	199.2	197.6	196.8
2006	198.3	198.7	199.8	201.5	202.5	202.9	203.5	203.9	202.9	201.8	201.5	201.8
2007	202.416	203.499	205.352	206.686	207.949	208.352	208.299	207.917	208.490	208.936	210.177	210.036
2008	211.080	211.693	213.528	214.823	216.632	218.815	219.964	219.086	218.783	216.573	212.425	210.228
2009	211.143	212.193	212.709	213.240	213.856	215.693	215.351	215.834	215.969	216.177	216.330	215.949
2010	216.687	216.741	217.631	218.009	218.178	217.965	218.011	218.312	218.439	218.711	218.803	219.179
2011	220.223	221.309	223.467	224.906	225.964	225.722	225.922	226.545	226.889	226.421	226.230	225.672
2012	226.665	227.663	229.392	230.085	229.815	229.478	229.104	230.379	231.407	231.317	230.221	229.601
2013	230.280	232.166	232.773	232.531	232.945	233.504	233.596	233.877	234.149	233.546	233.069	233.049
2014	233.916	234.781	236.293	237.072	237.900	238.343	238.250	237.852	238.031	237.433	236.151	234.812
2015	233.707	234.722	236.119	236.599	237.805	238.638	238.654	238.316	237.945	237.838	237.336	236.525
2016	236.916	237.111	238.132	-	-	-	-	-	-	-	-	-

See footnotes at end of table.

Table 24. Historical Consumer Price Index for All Urban Consumers (CPI-U): U. S. city average, all items-Continued

(1982-84=100, unless otherwise noted)

Year	Semiannual averages		Annual avg.	Percent change from previous	
	1st half	2nd half		Dec.	Annual avg.
1970	-	-	38.8	5.6	5.7
1971	-	-	40.5	3.3	4.4
1972	-	-	41.8	3.4	3.2
1973	-	-	44.4	8.7	6.2
1974	-	-	49.3	12.3	11.0
1975	-	-	53.8	6.9	9.1
1976	-	-	56.9	4.9	5.8
1977	-	-	60.6	6.7	6.5
1978	-	-	65.2	9.0	7.6
1979	-	-	72.6	13.3	11.3
1980	-	-	82.4	12.5	13.5
1981	-	-	90.9	8.9	10.3
1982	-	-	96.5	3.8	6.2
1983	-	-	99.6	3.8	3.2
1984	102.9	104.9	103.9	3.9	4.3
1985	106.6	108.5	107.6	3.8	3.6
1986	109.1	110.1	109.6	1.1	1.9
1987	112.4	114.9	113.6	4.4	3.6
1988	116.8	119.7	118.3	4.4	4.1
1989	122.7	125.3	124.0	4.6	4.8
1990	128.7	132.6	130.7	6.1	5.4
1991	135.2	137.2	136.2	3.1	4.2
1992	139.2	141.4	140.3	2.9	3.0
1993	143.7	145.3	144.5	2.7	3.0
1994	147.2	149.3	148.2	2.7	2.6
1995	151.5	153.2	152.4	2.5	2.8
1996	155.8	157.9	156.9	3.3	3.0
1997	159.9	161.2	160.5	1.7	2.3
1998	162.3	163.7	163.0	1.6	1.6
1999	165.4	167.8	166.6	2.7	2.2
2000	170.8	173.6	172.2	3.4	3.4
2001	176.6	177.5	177.1	1.6	2.8
2002	178.9	180.9	179.9	2.4	1.6
2003	183.3	184.6	184.0	1.9	2.3
2004	187.6	190.2	188.9	3.3	2.7
2005	193.2	197.4	195.3	3.4	3.4
2006	200.6	202.6	201.6	2.5	3.2
2007	205.709	208.976	207.342	4.1	2.8
2008	214.429	216.177	215.303	.1	3.8
2009	213.139	215.935	214.537	2.7	-.4
2010	217.535	218.578	218.056	1.5	1.6
2011	223.598	226.280	224.939	3.0	3.2
2012	228.850	230.338	229.594	1.7	2.1
2013	232.366	233.548	232.957	1.5	1.5
2014	236.384	237.088	236.736	.8	1.6
2015	236.265	237.769	237.017	.7	.1
2016	-	-	-	-	-

- Data not available.
NOTE: Index applies to a month as a whole, not to any specific date.

Roxie McCullar, CPA
8625 Farmington Cemetery Road
Pleasant Plains, IL 62677

Roxie McCullar is a regulatory consultant. She is a licensed Certified Public Account in the state of Illinois. She received her Master of Arts degree in Accounting from the University of Illinois-Springfield. She received her Bachelor of Science degree in Mathematics from Illinois State University. Over the past 18 years Ms. McCullar has filed testimony in over 40 state regulatory proceedings on cost allocation, universal service, and depreciation issues. In addition, Ms. McCullar has assisted Mr. Dunkel in numerous other proceedings.

PRESENT POSITION

William Dunkel and Associates
Position: Consultant

- Prefiled testimony on behalf Public Interest Advocacy Staff of the Georgia Public Service Commission in Georgia Power Company's 2016 Integrated Resource Plan, Georgia Docket No. 40161 in which I addressed depreciation issues.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in a general rate proceeding involving Atmos Energy, Docket No. 16-ATMG-079-RTS in which I addressed natural gas depreciation rate issues.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in an audit involving Twin Valley Telephone, Inc., Docket No. 15-TWVT-213-AUD in which I addressed cost study issues, allocation of FTTH equipment, and support fund adjustments.
- Testified on behalf of the Kansas Corporation Commission Staff in a general rate proceeding involving Kansas City Power Light Company, Docket No. 15-KCPE-116-RTS in which I addressed electric depreciation rate issues.
- Testified on behalf of the Kansas Corporation Commission Staff in an audit involving Moundridge Telephone Company, Inc., Docket No. 15-MRGT-097-AUD in which I addressed cost study issues and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in an audit involving S&T Telephone Cooperative, Inc., Docket No. 14-S&TT-525-KSF in which I addressed cost study issues, allocation of FTTH equipment, and support fund adjustments.
- Co-Sponsored Bench Report on Depreciation in Maine Docket No. 2013-00443 regarding Bangor Hydro Electric Company and Maine Public Service Company (Emera-Maine) depreciation rates in a general rate proceeding.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in an audit involving Wamego Telecommunications Company, Inc., Docket No. 14-WTCT-142-KSF in which I addressed cost study issues, allocation of FTTH equipment, and support

fund adjustments.

- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in an audit involving People Telecommunication LLC, Docket No. 13-PLTT-678-KSF in which I addressed cost study issues, allocation of FTTH equipment, and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in an audit involving J.B.N. Telephone Company, Inc., Docket No. 13-JBNT-437-KSF in which I addressed cost study issues, allocation of FTTH equipment, and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in an audit involving Zenda Telephone Company, Inc., Docket No. 13-ZENT-065-AUD in which I addressed cost study issues, allocation of FTTH equipment, and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in an audit involving Craw-Kan Telephone Cooperative, Inc., Docket No. 13-CRKT-268-KSF in which I addressed cost study issues, allocation of FTTH equipment, and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in an audit involving LaHarpe Telephone Company, Inc., Docket No. 12-LHPT-875-AUD in which I addressed cost study issues, allocation of FTTH equipment, and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in an audit involving Gorham Telephone Company, Docket No. 12-GRHT-633-KSF in which I addressed cost study issues, allocation of FTTH equipment, and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in an audit involving S&T Telephone Cooperative Association, Inc., Docket No. 12-S&TT-234-KSF in which I addressed cost study issues, allocation of FTTH equipment, and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving Cunningham Telephone Company, Inc., Docket No. 11-CNHT-659-KSF in which I addressed cost study issues, allocation of FTTH equipment, and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving Rainbow Telephone Association, Docket No. 11-RNBT-608-KSF in which I addressed cost study issues, allocation of FTTH equipment, and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving Pioneer Telephone Association, Docket No. 11-PNRT-315-KSF in which I addressed cost study issues, allocation of FTTH equipment, and support fund adjustments.
- Assisted Kansas Corporation Staff in audit involving Golden Belt Telephone Association,

Docket No. 10-GNBT-526-KSF in which I addressed cost study issues and support fund adjustments.

- Assisted Kansas Corporation Staff in audit involving United Telephone Association, Docket No. 10-UTAT-525-KSF in which I addressed cost study issues and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving Haviland Telephone Company, Inc., Docket No. 10-HVDT-288-KSF in which I addressed cost study issues and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving Blue Valley Tele-Communications, Inc., Docket No. 09-BLVT-913-KSF in which I addressed cost study issues, allocation of FTTH equipment, and support fund adjustments.
- Assisted Kansas Corporation Staff in audit involving Twin Valley Telephone Company, Docket No. 09-TVWT-069-KSF in which I addressed cost study issues, allocation of FTTH equipment, and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving Mutual Telephone Company, Docket No. 09-MLTL-091-KSF in which I addressed cost study issues and support fund adjustments.
- Assisted Kansas Corporation Staff in audit involving Columbus Telephone Company, Docket No. 08-CBST-400-KSF in which I addressed cost study issues, allocation of FTTH equipment, and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving Moundridge Telephone Company, Docket No. 08-MRGT-221-KSF in which I addressed cost study issues and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving Peoples Telecommunications, LLC, Docket No. 07-PLTT-1289-AUD in which I addressed cost study issues and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving Madison Telephone, LLC, Docket No. 07-MDTT-195-AUD in which I addressed cost study issues and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving Rainbow Telecommunications Association, Inc., Docket No. 06-RNBT-1322-AUD in which I addressed cost study issues and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving Wamego Telecommunications Company, Inc., Docket No. 06-WCTC-1020-AUD in which I addressed cost study issues, allocation of FTTH equipment, and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving H&B Communications, Inc., Docket No. 06-H&BT-1007-AUD in which I addressed cost study issues, allocation of FTTH equipment, and support fund adjustments.

- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving Elkhart Telephone Company, Inc., Docket No. 06-ELKT-365-AUD in which I addressed cost study issues, allocation of FTTH equipment, and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving South Central Telephone Association, Inc., Docket No. 05-SCNT-1048-AUD in which I addressed cost study issues and support fund adjustments.
- Prefiled testimony on behalf of the Utah Committee of Consumer Services in general rate case involving Carbon/Emery Telecom, Inc., Docket No. 05-2302-01 in which I addressed cost study issues and depreciation rates.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving Totah Communications, Inc., Docket No. 05-TTHT-895-AUD in which I addressed cost study issues and support fund adjustments.
- Prefiled testimony on behalf of the Maine Office of Public Advocate in Docket No. 2005-155, an investigation of Verizon's alternative form of regulation in which I addressed depreciation calculations.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving Tri-County Telephone Association, Docket No. 05-TRCT-607-KSF in which I addressed cost study issues and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving KanOkla Telephone Association, Inc, Docket No. 05-KOKT-060-AUD in which I addressed cost study issues and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving Cunningham Telephone, Inc, Docket No. 05-CNHT-020-AUD in which I addressed cost study issues and support fund adjustments.
- Testified on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving United Telephone Association, Inc, Docket No. 04-UTAT-690-AUD in which I addressed cost study issues and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving Council Grove Telephone Company, Docket No. 04-CGTT-679-KSF in which I addressed cost study issues and support fund adjustments.
- Testified on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving Golden Belt Telephone Association, Docket No. 04-GNBT-130-AUD in which I addressed cost study issues and support fund adjustments.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving Twin Valley Telephone, Inc., Docket No. 03-TWVT-1031-AUD in which I addressed cost study issues.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving Haviland Telephone Company, Docket No. 03-HVDT-664-RTS in which I addressed cost study issues and support fund adjustments.
- Testified on behalf of the Kansas Corporation Commission Staff in general rate

proceeding and audit involving Wheat State Telephone Company, Docket No. 03-WHST-503-AUD, in which I addressed cost study issues and support fund adjustments.

- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in general rate proceeding and audit involving S&A Telephone Company, Docket No. 03-S&AT-160-AUD, in which I addressed cost study issues.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in a general rate proceeding and audit involving JBN Telephone Company, Docket No. 02-JBNT-846-AUD, in which I addressed cost study issues.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in a general rate proceeding and audit involving Blue Valley Telephone Company, Inc., Docket No. 02-BLVT-377-AUD, in which I addressed cost study issues.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in a general rate proceeding and audit involving S&T Telephone Cooperative Association, Inc., Docket No. 02-S&TT-390-AUD, in which I addressed cost study issues.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in a general rate proceeding and audit involving Craw-Kan Telephone Cooperative, Docket No. 01-CRKT-713-AUD, in which I addressed cost study issues.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in a general rate proceeding and audit involving Sunflower Telephone Company, Inc., Docket No. 01-SFLT-879-AUD, in which I addressed cost study issues.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in a general rate proceeding and audit involving Bluestem Telephone Company, Inc., Docket No. 01-BSST-878-AUD, in which I addressed cost study issues.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in a general rate proceeding and audit involving Pioneer Telephone Company, Docket No. 01-PNRT-929-AUD, in which I addressed cost study issues.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in a general rate proceeding and audit involving Southern Kansas Telephone Company, Docket No. 01-SNKT-544-AUD, in which I addressed cost study issues.
- Prefiled testimony on behalf of the Kansas Corporation Commission Staff in a general rate proceeding and audit involving Rural Telephone Company, Docket No. 01-RRLT-518-KSF, in which I addressed cost study issues.
- Testified on behalf of the Government and Consumers Intervenors (GCI) before the Illinois Commerce Commission in an Alternative Regulation case involving Ameritech Illinois, Docket No. 98-0252, in which I addressed cost study issues.

Currently participating in the following proceedings:

- Arizona Docket No. E-01933A-15-0322 (Tuscon Electric Power Company Depreciation Issues)
- New Jersey BPU Docket No. GR15111304 (New Jersey Natural Gas General Rate Proceeding)

- Massachusetts Case No. D.P.U. 15-155 (National Grid (Massachusetts Electric Company/Nantucket Electric Company) Depreciation Issues)

Participated in, but did not testify in, the following proceedings:

- New Mexico Case No. 15-00261-UT (Public Service Company of New Mexico General Rate Proceeding)
- Alaska Docket No. U-15-089 (College Utilities Corporation and Golden Heart Utilities, Inc. Water and Wastewater Depreciation Issues)
- Maryland Case No. 9355 (Baltimore Gas Electric Depreciation Rate Proceeding)
- Nebraska Application NG-0079 (SourceGas Depreciation Rate Proceeding)
- Maine Docket No. 2013-00168 (Central Maine Power Company General Rate Proceeding)
- New Jersey BPU Docket No. GR13111137 (South Jersey Gas Company General Rate Proceeding)
- Utah Docket No. 13-057-19 (Questar Gas Company Depreciation Rate Proceeding)
- DC Formal Case No. 1103 (Potomac Electric Company General Rate Proceeding)
- New Jersey BPU Docket No. ER12121071 and OAL Docket No. PUC00617-13 (Atlantic City Electric Company General Rate Proceeding)
- Utah Docket No. 13-035-02 (Rocky Mountain Power Depreciation Rate Proceeding)
- Alaska Docket No. U-12-149 (ML&P Depreciation Rate Proceeding)
- DC Formal Case No. 1093 (Washington Gas Light General Rate Proceeding)
- Kansas Docket No. 12-KGSG-835-RTS (Kansas Gas Rate Proceeding)
- Kansas Docket No. 12-KCPE-764-RTS (Kansas City Power & Light General Rate Proceeding)
- Indiana Cause No. 44075 (Indiana Michigan Power Company General Rate Proceeding)
- Kansas Docket No. 12-ATMG-564-RTS (Atmos Energy General Rate Proceeding)
- Maryland Case No. 9286 (Potomac Electric Power Company General Rate Proceeding)
- Maryland Case No. 9285 (Delmarva Power & Light Company General Rate Proceeding)
- Kansas Docket No. 12-WSEE-112-RTS (Westar Energy, Inc. General Rate Proceeding)
- Kansas Docket No. 11-MDWE-609-RTS (Midwest Energy General Rate Proceeding)
- Kansas Docket No. 08-GIMX-1142-GIV (Generic Depreciation Docket)
- New Mexico Case No. 10-00086-UT (Public Service Company of New Mexico General Rate Proceeding)
- Georgia Public Service Commission Docket No. 31647 (Atlanta Gas Light Company Rate Proceeding)
- Kansas Docket No. 10-KCPE-415-RTS (Kansas City Power & Light General Rate Proceeding)
- DC Formal Case No. 1076 (PEPCO General Rate Proceeding)
- Missouri Case No. ER-2010-0036 (AmerenUE Electric Rate Proceeding)

- Michigan Case No. U-15981 (Wisconsin Electric Power Company Depreciation Rate Proceeding)
- Alaska Docket No. U-09-097 (Chugach Electric Association, Inc. Depreciation Rate Proceeding)
- Alaska Docket No. U-09-077 (Homer Electric Association, Inc. Depreciation Rate Proceeding)
- Alaska Docket No. U-09-029 (TDX Sand Point Generating, Inc. Depreciation Rate Proceeding)
- Michigan Case No. U-15778 (SEMCO Energy Gas Company Depreciation Rate Proceeding)
- Michigan Case No. U-15699 (Michigan Consolidated Gas Company Depreciation Rate Proceeding)
- Michigan Case No. U-15629 (Consumers Energy Company Depreciation Rate Proceeding)
- New Mexico Case No. 08-00273-UT (Public Service Company of New Mexico General Rate Proceeding)
- Missouri Case No. ER-2008-0318 (AmerenUE Electric Rate Proceeding)
- Missouri Case No. ER-2008-0093 (Empire District Electric Company General Rate Proceeding)
- Kansas Docket No. 08-MDWE-594-RTS (Midwest Energy General Rate Proceeding)
- Alaska Docket No. U-07-174 (Enstar Natural Gas Company and Alaska Pipeline Company Depreciation Rate Proceeding)
- Alaska Docket No. U-08-004 (Anchorage Water and Wastewater Utility Depreciation Rate Proceeding)
- Kansas Case No. 08-ATMG-280-RTS (Atmos Energy General Rate Proceeding)
- Kansas Case No. 08-SEPE-257-DRS (Sunflower Electric Depreciation Rate Proceeding)
- Maryland Case No. 9103 (WGL Depreciation Rate Proceeding)
- Maryland Case No. 9096 (BGE Depreciation Rate Proceeding)
- Maryland Case No. 9092 (PEPCO General Rate Proceeding)
- Missouri Case No. ER-2007-0002 (AmerenUE Electric Rate Proceeding)
- Maryland Case No. 9062 (Chesapeake Utility Corporation General Rate Proceeding)
- Indiana Cause No. 42959 (Indiana Michigan Power Company Depreciation Rate Case)
- Arizona Docket No. T-0151B-03-0454 (Qwest Renewed Price Regulation Plan)
- Illinois Docket No. 04-0461 (SBC Imputation Requirements)
- Utah Docket No. 04-049-62 (Qwest Price Cap Compliance Filing)
- Utah Docket No. 03-049-49 (Qwest Price Flexibility-Residential)
- Utah Docket No. 03-049-50 (Qwest Price Flexibility-Business)
- Alaska Docket Nos. U-1-83, U-01-85, U-01-87 (General Rate Proceeding)
- Maryland Case No. 8960 (Washington Gas Light Company Depreciation Rate
- Proceeding)
- Pennsylvania Docket Nos. C-200271905 (Access Charge Complaint Proceeding)

- Illinois Docket No. 03-0323 (IL UNE Law Proceeding)
- Illinois Docket No. 02-0864 (SBC UNE Rate Proceeding)
- Pennsylvania Docket Nos. A-310200F0002, A-311350F0002, A-310222F0002, A-310291F0003 (Verizon for Approval of Agreement and Plan of Merger)
- California Docket A.02-01-004 (Kerman General Rate Case)
- Pennsylvania Docket Nos. P-00991649, P-00991648, M-00021596 (Joint Petition for Global Resolution of Telecommunications Proceedings)
- Illinois Docket No. 02-0560 (Verizon Advanced Services Waiver)
- Utah Docket No. 01-2383-01 (Qwest Price Flexibility-Residential)
- Utah Docket No. 02-049-82 (Qwest Price Flexibility-Business)
- Missouri Docket No. TR-2001-65 (Cost of Access Proceeding)
- Kansas Docket No. 02-WLST-210-AUD (Audit and General Rate Proceeding)
- Kansas Docket No. 02-HOMT-209-AUD (Audit and General Rate Proceeding)
- New Mexico Case No. 3223 (Universal service fund proceeding)
- Arizona Docket No. T-00000A-00-0194 (Wholesale cost/UNE proceeding of Qwest)
- Arizona TX 98-00716 (Tax Case of Citizens Telecommunications Company of White Mountain, et. al.)
- Maryland Case No. 8862 (PIC change charge case of Verizon Maryland)
- Maryland Case No. 8745 (Universal Service Proceeding of Verizon-Maryland)
- Arizona Docket No. T-01051B-99-0105 (General rate case of Qwest)
- New Mexico Case No. 3300 (Subsidy case of VALOR)
- New Mexico Case No. 3325 (Subsidy case of Qwest)
- New Mexico Case No. 3008 (General Rate/Depreciation case of USWest)
- Arizona Docket No. T-02724A-00-0595 (Earnings Review of Table Top Telephone Co.)
- Arizona Docket No. T-01051B-97-0689 (Depreciation case of US West)
- Illinois Docket No. 99-0412 (EAS case involving Geneseo Telephone Company)
- Kansas Docket No. 00-UTDT-455-GIT (Universal Service Fund case involving Sprint)
- Kansas Docket No. 98-SWBT-677-GIT (Universal Service Fund case involving SWBT)
- Illinois Docket Nos. 98-0200/98-0537 (Consolidated) (Usage sensitive service of GTE)
- Kansas Docket No.98-SWBT-431-DRS (Depreciation case of SWBT)
- Florida Undocketed Special Project (Fair and Reasonable Rates of GTE, BellSouth, and Sprint)
- Pennsylvania Docket No. A-310125F002 (GTE North Interconnection Proceeding)
- Oklahoma Cause No. PUD 96-0000214 (Public Service of Oklahoma Depreciation Case)
- Hawaii Docket No. 7702 (GTE Hawaiian Tel Interconnection/avoided cost proceeding)
- Washington Docket No. UT-960369 (US West avoided cost proceeding)

Participation in the above proceeding included some or all of the following:

Developing analyses, preparing data requests, analyzing issues, writing draft testimony, preparing data responses, preparing draft questions for cross examination, drafting briefs, and developed various quantitative models.

EDUCATION

Master of Arts in Accounting from the University of Illinois-Springfield, Springfield, Illinois.

12 hours of Business and Management classes at Benedictine University-Springfield College in Illinois, Springfield, Illinois.

27 hours of Graduate Studies in Mathematics at Illinois State University, Normal, Illinois.

Bachelor of Science in Mathematics from Illinois State University, Normal, Illinois.

Relevant Coursework:

-Calculus
-Number Theory
-Linear Programming
-Finite Sampling
-Introduction to Micro Economics
-Principles of MIS
-Intermediate Managerial Accounting
-Intermediate Financial Accounting I
-Advanced Financial Accounting
-Accounting Information Systems
-Fraud Forensic Accounting
-Commercial Law
-Advanced Auditing
-Discrete Mathematics
-Mathematical Statistics
-Differential Equations
-Statistics for Business and Economics
-Introduction to Macro Economics
-Introduction to Financial Accounting
-Introduction to Managerial Accounting
-Intermediate Financial Accounting II
-Auditing Concepts/Responsibilities
-Federal Income Tax
-Accounting for Government & Non-Profit
-Advanced Utilities Regulation
-Advanced Corporation & Partnership Taxation

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-01933A-15-0322

DIRECT

TESTIMONY

OF

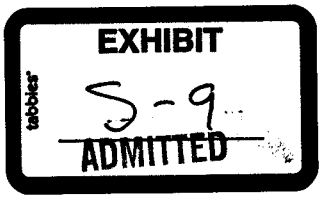
ERIC VAN EPPS

EXECUTIVE CONSULTANT

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 3, 2016



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EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NOS. E-01933A-15-0322 ET AL,

This testimony addresses the proposed pro forma adjustments to operating income from the Environmental Cost Adjustor ("ECA"), Demand-side Management ("DSM"), and Renewable Energy Standard and Tariff ("REST") adjustors.

Tucson Electric Power Company ("TEP") has proposed Revenue Requirement Adjustments which reduce pro-forma Operating Income by $1.261 million for the ECA and $28.478 million for the REST & DSM adjustors. These adjustments to test year operating results are necessary to assure that the new base rates authorized by the Commission in the pending rate case do not include the recovery of expenses that will be recovered through separately approved cost recovery mechanisms. Staff has reviewed these adjustments and recommends that they be approved.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Eric Van Epps. I am an Executive Consultant employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as an Executive Consultant.

A. As an Executive Consultant, I provide recommendations to the Commission on matters involving electric and gas utilities. I also perform studies on ancillary issues pertaining to matters concerning the electric industry.

Q. Please describe your educational background and professional experience.

A. I have a bachelor's degree in Business Administration and Political Science, specializing in international business and international politics from Arizona State University. I also graduated with a degree in Sustainability with a focus on alternative energy and resources from Arizona State University. I have been employed with the Commission since January of 2013.

Q. What is the scope of your testimony in this case?

A. I will address the Environmental Cost Adjustor ("ECA"), Demand-side Management ("DSM") and Renewable Energy Standard and Tariff ("REST") for Tucson Electric Power Company. ("TEP" or "Company").

Q. Have you reviewed the testimony submitted by the Company in this case?

A. Yes. I reviewed the testimony of Company witness, Mr. Dallas J. Dukes, specifically regarding the ECA, REST and DSM revenue requirement adjustments.

Mr. Dukes is proposing a revenue requirement adjustment which reduces test year actual operating income by $28.478 million for the REST and DSM and $1.261 million for the ECA. These pro-forma adjustments are necessary to remove test year revenues and expenses recovered through the adjustors from the company's operating income used to set base rates.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Please summarize your Revenue Requirement adjustment recommendations.

A. My revenue requirement adjustment recommendations are summarized in the following table:

Table 1

	Per Company	Per Staff	Staff Adjustment
ECA	$1,260,631	$1,260,631	--
REST & DSM	$28,478,062	$28,478,062	--

ENVIRONMENTAL COST ADJUSTOR

Q. Why has the Company requested a revenue requirement adjustment for the ECA?

A. The pro-forma adjustment removes all test year revenues collected under the current ACC-approved ECA mechanism. These revenues are not collected as part of base rates, so they must be excluded from Test-Year revenues used to calculate new base rates.

Q. What is the ECA?

A. The ECA is an adjustor mechanism that allows the company to recover capital project carrying costs and incremental O&M costs related to environmental investments made by TEP and not already included in rate base or recovered through another Commission approved adjustment.

Q. Does Staff recommend the Company's ECA pro forma adjustment to reduce operating income by $1,260,631?

A. Yes.

DEMAND-SIDE MANAGEMENT

Q. Why has the Company requested a revenue requirement adjustment for its DSM program?

A. The DSM program has a separate funding mechanism. Thus, TEP has requested that the expense activity directly related to the DSM program be excluded from test-year pro-forma revenue and expenses.

Q. What is the expense activity directly related to the DSM program?

A. Based on the Company's working papers, the DSM program incurred $3,149,228 in operating income during the test year.

Q. Were you able to reconcile DSM expenses against the Company's Annual DSM Progress Report?

A. Yes, within a de minimis amount Staff was able to reconcile the working papers against the Annual DSM Progress Report.

RENEWABLE ENERGY STANDARD AND TARIFF

Q. Why has the Company requested a revenue requirement adjustment for its REST program?

A. The REST program has a separate funding mechanism. Thus, TEP has requested that the expense activity directly related to the REST program be excluded from test-year pro-forma revenue and expenses.

Q. What is the expense activity directly related to the REST program?

A. Based on the Company's working papers, the REST program incurred $25,328,835 in operating income during the test year.

Q. Were you able to reconcile REST expenses against the Company's Annual REST Compliance Report?

A. Yes, within a de minimis amount Staff was able to reconcile the working papers against the Annual REST Compliance Report.

Q. Does Staff recommend accepting the Company's REST and DSM pro forma adjustments to reduce operating income by a total of $28,478,062?

A. Yes, the pro forma adjustment which reduces operating income by $28,478,062 is reasonable and adequately excludes revenue and expense activity directly related to monies collected through the REST and DSM adjustor programs.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
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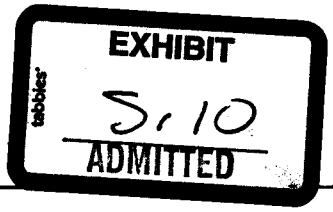
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-01933A-15-0322

DIRECT
RATE DESIGN TESTIMONY
OF
HOWARD SOLGANICK
ON BEHALF OF THE
UTILITIES DIVISION STAFF
ARIZONA CORPORATION COMMISSION

JUNE 24, 2016



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Typical Residential and Small General Service Bill Comparison HS-5

EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NOS. E-01933A-15-0322 AND E-01933A-15-0239

Mr. Solganick's direct rate design testimony reviews the Tucson Electric Power Company ("TEP" or "Company") proposal for cost of service, revenue allocation, rate design, and modifications to the Lost Fixed Cost Recovery mechanism ("LFCR").

Taking a multi-case view, the Arizona Corporation Commission Utilities Division Staff ("Staff") recommends that the long-term (but not this case) rate design should focus on a three-part rate (customer, demand and energy) including time-of-use ("TOU") to better and more accurately relate rates to underlying costs. For informational and educational purposes only, Staff proposes the Company provide all residential and small general service customers with their monthly On-Peak and Off-Peak demands. Staff recommends that the Company offer customers access to their usage information through a website or other means of access. The Company should also develop an education program to help customers understand their usage information and how customers can manage their usage and change the size of their bills.

Mr. Solganick evaluates TEP's Class Cost of Service Study ("CCoSS")and places its results into perspective, and Staff recommends that it be used as a guide to revenue allocation and a source of unit cost data for rate design.

Mr. Solganick provides the Staff recommendation for the allocation of Staff's recommended rate increase among the six major rate classes. This recommendation is tempered by the concept of gradualism due to the changes in rate base and changes in TEP's proposed cost allocation methodology for generation plant along with the recognition of the purchase of a share of Gila River Unit No. 3.

Based on a review of TEP's application, responses to Staff data requests and consistent with Staff's long-term rate design plan, Mr. Solganick provides recommendations for the rate design for each of TEP's rate classes along with Lifeline, distributed generation, service fees, the Buy-Through provision, Automated Metering Infrastructure ("AMI") Opt-Out customers and the Economic Development proposal of TEP. The impact of Staff's proposed rate design is provided for residential ("RES") and small general service ("SGS") customers.

Staff recommends that the Commission accept TEP's proposal to eliminate the Fixed Charge Option from the LFCR mechanism. Staff recommends that the Commission reject the Company's other LFCR proposals.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Howard Solganick. I am a Principal at Energy Tactics & Services, Inc. My business address is 810 Persimmon Lane, Langhorne, PA 19047. I am performing this assignment under subcontract to Blue Ridge Consulting Services, Inc. ("Blue Ridge").

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("Commission").

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. I have testified and/or presented testimony (summarized in Exhibit HS-1) before the following regulatory bodies:

- Arizona Corporation Commission
- Delaware Public Service Commission
- Georgia Public Service Commission
- Jamaica (West Indies) Electricity Appeals Tribunal
- Maine Public Utilities Commission
- Maryland Public Service Commission
- Michigan Public Service Commission
- Missouri Public Service Commission
- New Jersey Board of Public Utilities
- Public Utilities Commission of Ohio
- Pennsylvania Public Utility Commission
- Public Utility Commission of Texas

Q. What is the purpose of your rate design testimony?

A. My testimony provides Staff's long-term plan for rate design, analyzes the Class Cost of Service Study ("CCoSS"), Staff's recommended allocation of the revenue increase proposed by Staff, and recommends how the increased revenue should be implemented within the

Company's various existing and proposed rates. I also present Staff's recommendations to address Lifeline rates, distributed generation ("DG"), Service Fee charges, Buy-Through provision, Automated Metering Infrastructure ("AMI") Opt-Out and economic development. Finally, I present Staff's recommendations for the existing Lost Fixed Cost Recovery ("LFCR") mechanism.

Q. Are you the only Staff witness providing direct rate design testimony in this docket?

A. No. The following people will also be providing direct rate design testimony.

- Mr. Michael McGarry will be addressing the proposed modifications to the Purchase Power and Fuel Adjustment Clause.
- Mr. Bob Gray will be addressing the expansion of the TEP-Owned Rooftop Solar program and the proposed Residential Community Solar program.
- Mr. Matt Connolly will be addressing the proposed residential prepay metering program and several compliance requirements.
- Mr. Eric Van Epps will be addressing the proposed changes to the Environmental Compliance Adjustor, Demand Side Management Surcharge and the Renewable Energy Standard and Tariff Surcharge.

DIRECT TESTIMONY

Q. Please summarize Staff's positions?

A. Staff recommends:

Long-Term Rate Design Plan

Over the long term, rates should be based on costs and recognize the concepts of customer, demand and energy including time-of-use ("TOU"). When changes are made, gradualism should be recognized. The long-term plan is placed into the context of evolving metering and customer information capabilities.

Class Cost of Service Study

The purposes of a CCoSS are discussed along with the changes in the Company's CCoSS including a new production cost methodology.

Revenue Allocation

Staff recommends a revenue allocation among the customer classes based on moving all classes to cost of service but recognizing that gradualism is necessary due to the effects of a new production cost methodology and the Company's inclusion into rate base of a portion of the new Gila River Unit No. 3.

Rate Design

Staff recommends rate designs for each rate schedule and, consistent with the long-term rate design plan, recommends the implementation of optional Three Part-TOU rates for residential and small general service rates customers and a requirement that the Company begin to provide demand information for non-demand rate RES and SGS customers. Staff

also highlights areas where the Company should provide further information and justification for its proposals.

Staff highlights that due to the implementation of the proposed Medium General Service ("MGS") rate class the Commission should keep the rate design portion of the case open to resolve unanticipated customer rate impacts.

Miscellaneous Items

- Lifeline – Staff recommends that the level of this discount not be reduced and that the transition of these customers to standard residential rates with the addition of a single discount for Lifeline be continued.

- Distributed Generation – Staff notes that Commission Docket No. E-00000J-14-0023, which is intended to examine the value and cost of DG, will continue to provide useful information to the parties in this rate case. Therefore, at this time, Staff does not propose any changes to the existing net metering tariff or waivers of the net metering rules but it may update its position in its Surrebuttal testimony or later at the hearing in this case.

- Service Fee Charges – Staff analyzed the Company's proposals and recommends which fees should apply to Opt-Out customers.

- Buy-Through – Staff looks forward to the input of other parties and does not object to this mechanism if there are no adverse impacts and no costs to other customers.

- AMI Opt-Out – Staff recommends that a non-transmitting solid-state meter be used to accumulate information needed for billing, customer service and customer education along with recommended charges for the installation of the meter and monthly meter reading.

- Economic Development – Staff supports the establishment of the program but does not support any request for lost revenues.

LFCR

Based on a review of the Company's application, supporting testimony, and responses to data requests, Staff recommends that the Commission reject the Company's proposed changes to the LFCR mechanism that include:

- Allowing the Company to receive recovery for generation costs;
- Increasing the recovery for distribution demand costs from 50 percent to 100 percent;
- Increasing the cap on recovered costs allowed for each year from 1 percent to 2 percent;
- Expanding the LFCR mechanism to include revenues lost from an Alternate Generation or "Buy-Through" provision to be established in the Company's tariff; and
- Combining the Energy Efficiency ("EE") and DG portions of the mechanism on the customer's bill.

Based on a review of the Company's application, supporting testimony, and responses to data requests, Staff recommends that the Commission accept the Company's proposed change to the LFCR mechanism to eliminate the Fixed Cost Option.

LONG-TERM RATE DESIGN PLAN

Q. Are significant changes occurring in the Company's capability to measure how and when customers are using energy?

A. Yes. Based upon discussions between Staff and the Company, the Company expects to complete a significant majority (subject to a few geographic limitations) of its installation of AMI by the end of 2016.[1]

Q. How has electric metering changed over time?

A. Initially there was no metering, and infant utilities charged either a flat rate per customer or charged by the number of light bulbs installed by a customer. This pricing methodology is still used for lighting (and other fixed load) customers because the number and wattage of bulbs can be accurately verified and enumerated. By not using meters, the costs of meters and meter reading do not need to be charged to those customers.

With the advent of energy meters at a reasonable cost, coupled with a wider range of lighting and appliances, utilities began to charge customers based upon the energy consumed. This type of rate design did not recognize different costs based upon demand (often expressed as load factor). Two customers using identical amounts of energy but with different usage patterns could have different levels of demand and require different amounts of generation, transmission and distribution equipment (at very different costs), and therefore one customer may be undercharged and the other overcharged if demand was not measured and taken into account. Alternatively, two customers who require the same equipment might use very different amounts of energy and again would result in one customer being undercharged and the other overcharged.

[1] TEP Response to STF 1.16

The introduction of demand meters, which measure peak demand usage within the billing period along with energy consumed, allowed for the introduction of rate forms such as the three-part rate (customer, demand and energy) or a variant (hours of use). The use of the demand meter and associated rates reduced the disparate impact of energy-only rates. Demand meters have generally not been used for residential customers due to the cost of the more complex meter, and the increased complexity of billing and the information that should be provided to the customer. The residential class was often seen as homogenous enough not to have wide usage disparities and therefore the cost of demand meters and their associated rate complexity was not justified.

For a number of years utilities have been able to measure the consumption of energy over very narrow time periods (hourly or even 15 minute intervals) but the challenge has been recording that data cost effectively and then providing that data to customers so that the customer could decide whether and how to respond and change their usage (energy) or usage pattern (demand). Interval data have been used for load research to provide an understanding of how different customers use energy and the data were typically recorded on magnetic tape and analyzed in bulk. While interval data were suitable for load research purposes, it was difficult to provide the data to a large number of customers at a reasonable cost.

Similarly, time-of-use meters could accumulate energy usage in a few time-differentiated periods but these data were only recorded and reported as On-Peak, Shoulder and Off-Peak and did not offer much information to the customer, such as when the energy was used on an interval basis.

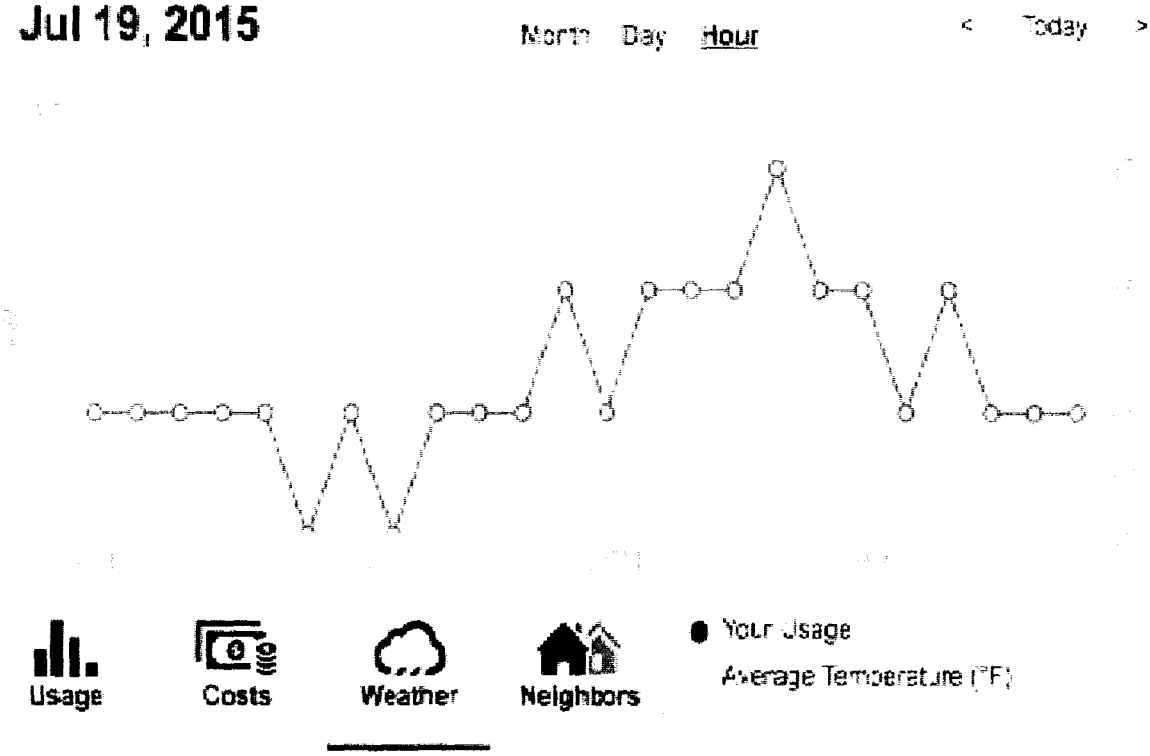
AMI has benefited from the declining costs of electronic versus mechanical metering devices and the ability to analyze data on a customer-specific basis. Utilities that have installed AMI often develop meter data management systems that allow for the extraction of energy and demand data for billing purposes. Unfortunately, some AMI planning does not go far enough and some utilities cannot provide individual customers their usage information in a form that supports customers' decisions about how and when to use energy more effectively and efficiently.

Q. Can you provide an example of conveying energy information to customers?

A. As a residential customer, my electric utility provides me with access to a portal where I can view my energy consumption.

On a macro basis, I can view my monthly consumption and compare it to an aggregate grouping of my neighbors and to a more limited aggregate grouping of my most efficient neighbors. The aggregate nature of these data protects my neighbors' privacy, and the portal limits my neighbors' access to my data, protecting my privacy. Various entities have opined that providing this "new" data encourages some customers into becoming more efficient in their use of energy.

My utility also provides me (with a two-day delay) my hourly energy consumption, which is equivalent to hourly demand. From this timely information, I can determine the peak period(s) of energy usage and then decide if I wish to change my energy timing, intensity and/or usage in the future.



Q. How did the confluence of new metering and information capabilities, changing customer characteristics lead Staff to consider a long-term rate design concept?

A. At this point in time, many utilities have the capability to record interval data as a result of the installation of AMI. Some utilities can provide that data to individual customers in a form that is somewhat easily understood, although some customer education is necessary. Residential customers are increasingly becoming non-homogenous as they adopt various forms of heat and distributed generation and as their lifestyles, demographics, and work patterns become increasingly more diverse.

Staff has raised the concept of offering a "plan" of how rate design should evolve so that the parties to this case could provide their input and the Commission could consider a plan in order to provide the Company's customers advance notice that changes are underway.

Q. Please articulate Staff's long-term rate design "plan".

A. There are a number of principles within this plan.

Rates should be based on costs derived from class cost of service studies not only at the class level but also to illuminate the unit costs of individual customer, demand and energy rates. Marginal costs should be given some consideration but embedded costs are the focus. There should be a place for test programs to determine if rate design can alter the need for capital investment and/or energy costs. When changes occur, gradualism should be used to temper the short-term impact until the next rate case.

Rate design should recognize the concepts of customer, demand and energy, and also recognize TOU and seasonality ("Three Part–TOU"). The number of rates available to customers should be minimized to avoid confusion as Three Part–TOU rates allow for cost-based billing of non-homogenous customers within one rate schedule. Inverted rates would be supplanted by the seasonal TOU component and the demand component which recognizes load factor.

Generation pricing would reflect the marketplace by considering seasonality, TOU, hourly pricing and demand response.

Rates should be supported by customer-specific usage information collected under extreme privacy and security, but available to customers along with tools to help them see the impact and make decisions. In the long-term, customers might receive cost "warning" using a simple red/yellow/green indication in their home or business and, for example, their demand controllers could access detailed price information online.

Rate subsidies, as determined appropriate, should be clearly delineated, be based on and computed from standard rates. For example, a Lifeline customer would be billed as a standard residential customer including all trackers and adjustment clauses but also receive a specific discount. Should a Lifeline customer's situation change for the better, the only change would be the removal of the Lifeline discount, which would be easily recognized by that customer. Hence, Staff's plan migrates Lifeline eligible customers to standard residential rates.

The Commission's Investigation of the Value and Cost of Distributed Generation (Docket No. E-00000J-14-0023) will assist Staff and the parties to determine an adequate methodology and quantification of compensation to potentially replace net metering. Ultimately if DG results in savings across the utility system and differentially for specific geographic areas (feeder), these effects would in time be separately identified using adders.

Q. Does the long-term migration of all customers of a class on to a single Three Part-TOU rate limit a customer's choice to one alternative?

A. Customers have very limited options now. The two-part rate allows the customer to increase or decrease his/her energy consumption to change the total bill. A two-part rate with TOU allows the customer to increase or decrease his/her energy consumption and when that energy is consumed but does not reflect the intensity or magnitude of use. The Three Part-TOU rate allows for a third dimension that the customer can use to affect the intensity of use.

One customer may come home from work, turn on the air conditioner, shower using hot water from an electric water heater and start the clothes washer all at the same time. A second customer may decide to linger with friends and have dinner out but have the air

conditioner begin to cool the home before arrival, shower later in the evening and set the clothes washer to start at 4 AM. The intensity of multiple electric appliances operating together places a greater load on the system than the load of a single appliance. The Three Part-TOU rate prices the consumption and usage pattern differently by charging for both the demand (intensity) and energy consumed separately. In each case, the customers can choose the usage and pattern they wish and be charged appropriately for raising or lowering the utility's costs.

Q. What would be the long-term impact of this rate design "plan"?

A. Customers would have greater information available to make their own energy decisions, and rates would more accurately price those decisions and lessen the consequential impact on other customers. Over time, customer and demand charges would gradually increase and energy charges would become "purer" and lower for the distribution component. A customer could reduce costs by adjusting demand and/or by changing energy usage. The customer benefits from tools and education to take the best advantage of new rate forms.

Q. Do Three Part-TOU rates increase revenues for the utility?

A. No. If properly implemented the rates are neutral for the utility at the end of the Test Year. However, if customers choose to react to their present usage patterns the utility may see a decrease in revenue.

Q. Do Three Part-TOU rates increase costs for customers?

A. If a customer's usage pattern is the same as a "typical" customer then there should be no significant impact as Three Part-TOU rates are implemented. If a customer has an atypical usage pattern then costs may increase (for lower load factor customers) or decrease (for higher load factor) customers.

Q. Are these concepts new or new to the utility?

A. For medium and large customers, demand rates have been the norm and a Three Part-TOU rate is available. Flat rates are still appropriate for fixed, predictable loads such as lighting, cable amplifiers and traffic signals.

In the previous TEP rate case (Docket No. E-01933A-12-0504), I raised a number of these concepts but did not articulate them as a plan. Similarly, in this case the Company has raised some of these concepts but has not provided the data and education components critical for customer understanding of the Company's proposed residential and small general service demand rates.

Q. What are the important principles for the move towards the long-term rate design plan?

A. Rate design should not be changed until customers have private, secure, easy, timely and comprehensible access to their usage data.

Q. Are you recommending a mandatory transition to Three Part-TOU rates for Residential ("RES") and Small General Service ("SGS") customers?

A. No, Staff is not recommending a mandatory transition to Three Part-TOU rates in this case. In the on-going UNS Electric ("UNSE") case (Docket No. E-04204A-15-0142) the consideration of Three Part-TOU rates for RES and SGS customers was conflated with the outstanding issues of net metering and cost shifts related to solar DG customers. Before the impact of the rates at the level of revenue requirements generally accepted by the parties could be considered, customer concerns (both real and alleged) caused UNSE to withdraw the request for mandatory transition to Three Part-TOU rates for Residential and SGS customers. Staff then decided to withdraw its support because forcing a utility into a

mandatory rate design change without the utility's support could lead to a flawed and failed transition.

Therefore, Staff is recommending in this case that an optional Three Part-TOU rate be made available to both RES and SGS customers. This optional rate may be attractive to customers that use energy efficiently and effectively.

Staff recommends that all RES and SGS customer bills include the customer's monthly On-Peak and Off-Peak demands (although the demand values would not be used for billing unless the customer has chosen the optional demand rate). Making the demand data available on the bill will allow customers to understand the concept of demand without any financial concerns.

Staff recommends that the Company should develop a customer information portal that would provide all customers with the ability to review their demand and energy consumption and evaluate various optional rate forms so that customers can make informed decisions about rates, energy efficiency and emerging technologies.

If the information now being measured and accumulated from AMI is not provided to customers then the full benefits of AMI will not be realized.

CLASS COST OF SERVICE STUDY

Q. What is the purpose of a fully allocated cost of service study?

A. Just as the rate case revenue requirements process studies each element of the Company's operations to determine the overall cost to operate the Company efficiently and effectively, a fully allocated cost of service study attempts to determine the individual cost to serve each

customer class and subclass. A fully allocated class cost of service study is intended to assist the Commission to allocate revenue requirements among customer classes.

Q. How can a regulator use the class cost of service study?

A. Because customer classes use the utility's system on an interrelated or shared basis, regulators have historically used a fully allocated class cost of service study as a guideline to allocate revenue among classes. Regulators typically also consider economic, social, historical and other factors that may affect customers when determining revenue allocation. Such considerations often result in rates that deviate from strict cost of service.

Q. Are there limitations to a cost of service study?

A. Yes. A class cost of service study involves judgment and decisions on the part of the practitioner in assigning costs to the various customer classes. In some situations, decisions are made to use a particular allocation factor for a particular account. In other situations, data used to develop an allocation factor are not always complete and/or timely and the practitioner must deal with the resulting uncertainty. Consequently, the cost of service study acts as a guide in revenue allocation and in formulating rate design.

Q. Has the Company provided a class cost of service study?

A. Yes. The Company provided its CCoSS based on the Test Year (twelve-month period ended June 30, 2015).[2] Schedule G provides the individual class returns for the Company's five major service classes (Residential, General Service, Large General Service, Large Power Service and Lighting) along with the proposed 138 kV class.

[2] TEP Filing Schedule G

Q. Have you reviewed the CCoSS presented by the Company?

A. Yes. The CCoSS was provided as Schedules G-1 through 7. I performed a review of the allocations, developed data requests and reviewed the answers to Staff and other parties.

Q. Did the Company adjust or normalize its revenues?

A. Yes. The Company used a Test Year (twelve months ending June 30, 2015) and then adjusted it to reflect more normal or appropriate (from the Company's viewpoint) conditions.[3]

Q. Has the CCoSS changed from the prior rate case (Docket No. E-01933A-12-0291)?

A. Yes. The prior CCoSS had six service classes (Residential, Small General Service, Large General Service, Large Light & Power, Mining and Lighting). The Residential, Small General Service and Lighting classes are similar. The Company has created new rate schedules for Medium General Service ("MGS") and 138 kV based on demand and voltage criteria from the SGS and Large General Service ("LGS")[4] and Large Power Service ("LPS") rate schedules respectively[5].

Q. Are the changes to the service classes appropriate?

A. Yes. The differentiation by demand and voltage proposed by the Company is appropriate. The combination[6] within this case's CCoSS General Service class of Small General Service and Medium General Service classes should be disaggregated in the Company's next CCoSS as the transition to the MGS rate schedule will have been completed.

[3] TEP Filing Schedule G-1 Inputs lines 1 to 4; Schedule G-2 lines 38 and 41
[4] Jones Direct 37:19
[5] Jones Direct 38:17
[6] TEP Response to Staff 20.13

Q. Have the Company's capacity resources changed since the last case?

A. Yes. The Company recently purchased a 75 percent share of the Gila River Power Plant Unit No. 3 combined cycle generating plant in concert with its affiliate UNSE.[7] The Company has changed its fuel mix by decreasing its coal capacity.[8]

Q. Please describe the attributes of a typical combined cycle generating unit?

A. A combined cycle generating unit is flexible in that it can start and stop operations (dispatch) easier than a coal or nuclear plant and is generally more thermally efficient than most other forms of fossil and nuclear generation. Typically, combined cycle plants are fueled by natural gas with distillate oil backup.

Q. What allocators does the Company use for its power supply expenses within the 2014 CCoSS?

A. For Other Production Plant, the Company uses the Demand Production ("DPROD") allocator, which is classified exclusively as demand.[9] For Other Production Expenses, the Company uses the Energy Production Power Supply – Design ("EFUELRD") allocator, which is classified exclusively as energy.[10]

Q. What allocator methodology did the Company use for DPROD?

A. The Company states that it used an Average and Excess allocator for production plant and expenses.[11]

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[7] Hutchens Direct 7:26
[8] Hutchens Direct 7:21
[9] TEP Schedule G-3, Accounts 310-316
[10] TEP Schedule G-4, Account 501
[11] Jones Direct 26:3

Q. Has the Company changed the selection of the DPROD allocator since the last case?

A. Yes. Previously, the Company used a Peaks and Average allocator in its 2012 CCoSS.[12]

Q. Is the Company's Average & Excess & 4CP allocator a standard production methodology?

A. Although the Company stated that it is using an Average and Excess allocator it was non-specific in written testimony about the construction of the allocator. However, the Company provided a table within its testimony showing the impact of various allocators on class returns.[13] Within this table, the Company describes its Average and Excess allocator as Average & Excess & 4CP, which, based on the title, would be non-standard. Using coincident peaks (one or more) within the average and excess allocator is not a standard or recommended methodology.

Q. Why do you say that Average & Excess & 4CP does not appear to be a standard methodology?

A. The Electric Utility Cost Allocation Manual indicates:

> "If your objective is – as it should be using this method – to reflect the impact of average demand on production plant costs, then it is a mistake to allocate the excess demand with a coincident peak allocation factor because it produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands."[14]

[12] Jones Direct 25:27
[13] Jones Direct 26:6
[14] NARUC Electric Utility Cost Allocation Manual January, 1992, page 50

Q. Did you explore this concern with the Company in the UNSE case?

A. Yes. The Company indicated that the DPROD allocator is a traditional A&E-NCP allocator but is allocating the 4CP value, thus the use of 4CP as an identifier. The Company confirmed this in an email during the UNS case.[15]

Q. Did the Company's DPROD allocator appear to meet the Company's description of an Average and Excess allocator?

A. No. The Company's DPROD allocator may be calculated using 4 CP along with the forms used for average and excess but the result is a 4CP allocator. This can be seen on Tab AvgEx&4CP of the Company's CCOSS which calculates the allocator.[16] The values for AED/4CP and 4CP Allocator are identical. The Company has indicated that the AED methodology was ordered in an Arizona Public Service case[17] (presumably Decision No. 69663). However, the methodology as implemented by the Company in this case is functionally the same as 4CP.

The effects of the equivalent 4 CP allocator can also be seen by Schedule G-1 line 7 where the Lighting class has not been allocated any fuel inventory. Even though the Lighting class has no responsibility under the 4CP portion of average and excess there should be an average component and none is apparent.

[15] Email from Craig Jones dated 10/13/15 3:12 AM Item 1
[16] 2015 TEP Schedule G – COSS Competitively Sensitive Confidential.xlsx
[17] Jones Direct 26:4

Q. Did Staff explore the Company's calculation of the Average and Excess-NCP allocator?

A. Staff issued additional data requests to explore this issue. The Company subsequently issued a Revised Schedule G (UDR 1.001) that incorporated the expected AED-NCP allocator along with changes to meter allocations and customer allocations.[18]

Q. What is Staff's recommendation for an appropriate methodology for the DPROD allocator?

A. The appropriate methodology is Average and Excess-NCP (noncoincident peaks) as supported by the National Association of Regulatory Utility Commissioners ("NARUC") Manual as noted above. This allocator reflects both average load (energy) and excess load (demand) without algebraically becoming a CP allocator. This methodology is a better fit to a capacity plan that focuses on both energy and capacity (and selects an efficient and flexible generation technology such as Gila River Unit No. 3).

Q. Are there disproportional impacts between the present CCoSS and the prior one?

A. As Confidential Exhibit HS-2 shows, the change for the Residential and SGS classes is higher than the change for the Company in total. For example, Net Production Plant increased by 47 percent for the Company but 57 percent for the Residential class, 59 percent for the SGS class and 79 percent for the LPS class. Net Distribution Plant increased by 20 percent for the Company but 63 percent for the Residential class, 12 percent for the SGS class and 4 percent for the LPS class.

[18] TEP Response to STF 20.11

Q. What is the impact of the Company's change to the DPROD allocator?

A. The use of the new DPROD allocation methodology (A&E-NCP) raises the allocation to lower load factor classes (more costs) compared to the prior Peaks and Average methodology.

Q. What is the result of the Company's capacity allocation proposal in this case?

A. The Company CCoSS provides a means to compare the impact of demand allocators (Average & Excess-NCP and Peaks & Average & 4CP) after the Company's proposed increase.[19] Assuming that only the production plant allocation methodology has changed, the class return for the Residential class has gone from 2.50 percent using P&A to 0.92 percent using A&E-NCP; General Service class 20.02 percent using P&A to 19.06 percent using A&E-NCP; Large General Service 20.04 percent using P&A to 25.81 percent using A&E-NCP.

Q. Does the Company's allocation of income taxes by class have an impact on the returns calculated?

A. Yes. The Company appears to allocate class income taxes on the sum of return times rate base plus operating expenses (without income taxes). Using this methodology, positive taxes are allocated to a class that is not providing enough revenue to cover expenses. An alternative methodology (sometimes used) calculates class income taxes based on the profitability of the class, more akin to how a business is taxed. The Company's methodology magnifies the disparity between positive and negative class returns. However, when all classes have positive returns close to the Company's return the effect is smaller and of less consequence than the other changes discussed above.

[19] TEP Revised Schedule G Tab AvgEx&4CP

There is no impact from the use of the Company's ratebase tax allocation methodology compared to allocating based on net income before income taxes when all classes reach parity (Unitized Rate of Return ("UROR") = 1.000). However, the impact under present conditions is significant. Assuming Staff's proposed revenue increase and revenue allocation (37.5% of UROR = 1.000) the Residential class UROR would increase from 0.028 to 0.308 due to the reallocation of $ 20.73 million of income tax expense. This approximates to a revenue impact for the Residential class of $33.63 million.

Q. What CCoSS recommendation does Staff have for the Commission?

A. There are two major effects operating in the same direction in this case. While the Company's net distribution plant has increased by 20 percent, net production plant has increased by 47 percent. Simultaneously, the Company has changed its production plant allocation methodology from Peak & Average to Average & Excess–NCP. These two changes magnify the individual impact on classes. Therefore, the Commission should use the Company's CCoSS as a general guideline and invoke gradualism in its class revenue allocation decision for this case.

REVENUE ALLOCATION

Q. What non-cost considerations should the Commission consider during its deliberations on revenue allocation?

A. The Commission should consider the relative positions (from the CCoSS) of the classes along with the qualitative issues such as economic conditions for consumers, the business climate for commercial and industrial customers and past practices when deciding what portion of a revenue increase is allocated to each class.

Q. What principles do you generally use to allocate revenue among rate classes?

A. I have used the following principles:

- The individual rate classes should be gradually moved toward an UROR of 1.000 over one or more rate cases depending on the frequency of rate cases and the distance of the class' UROR from 1.000.
- There should be an upper bound of 150 percent for any class' percentage increase in revenue compared to the overall percentage increase in revenue.
- There should be a lower bound of 50 percent for any class' increase compared to the overall increase.

Q. Are there other concepts that apply in this case?

A. The purchase of the combined cycle generating unit was intended to stabilize energy costs, which provides benefits to all customers. Therefore, it would be inappropriate to reduce rates for any customer class because that would send a confusing message about the new plant expenditure.

Q. What is the Company's proposed revenue allocation?

A. Based on Schedule H-1, the Company is proposing to allocate its requested $109.5 million increase 59.7 percent to the Residential class, 7.3 percent to the General Service class, 34.7 percent to the Large General Service class, -2.9 percent to the Large Power Service and 138kV classes and 1.1 percent to the Lighting class.

Q. Have you modeled various revenue allocations based on Staff's recommended revenue requirements?

A. Confidential Exhibit HS-4 models Staff's proposed $ 49,400,000 increase a number of ways. For comparison purposes the increase was allocated:

- Equal percentage increase (across the board by revenue)
- Moving all of the classes to the same return (UROR equals 1.000)
- Moving the Residential and Lighting classes 50 percent of the amount needed to reach parity (and decrease all other classes by $9.87 million)
- Moving the Residential and Lighting classes 45 percent of the amount needed to reach parity (and decrease all other classes by $3.94 million)
- Moving the Residential and Lighting classes 40 percent of the amount needed to reach parity (and increase all other classes by $1.98 million)
- Moving the Residential and Lighting classes 35 percent of the amount needed to reach parity (and increase all other classes by $7.91 million)
- Moving the Residential and Lighting classes 33.33 percent of the amount needed to reach parity (and increase all other classes by $9.89 million)
- Moving the Residential and Lighting classes 30 percent of the amount needed to reach parity (and increase all other classes by $13.84 million)
- Moving the Residential and Lighting classes 37.5 percent of the amount needed to reach parity (and increase all other classes by $4.95 million)

The remaining revenues from the other classes (GS, LGS, LPS and 138kV) were allocated based on their respective expected revenues (Test Year Adjusted Margin Revenues[20] plus Test Year Proposed Fuel Revenues[21]).

Q. What is Staff's recommendation on revenue allocation?

A. Based upon the present CCoSS, the principles discussed above, the impact of the purchase of the combined cycle plant, the change in allocation methodology and the relative impacts between classes, Staff recommends that the eventual revenue requirements be allocated by increasing the Residential and Lighting classes 37.5 percent of the amount needed to reach parity and increasing all other classes by $4.95 million (10 percent of the overall increase proposed by Staff) to obtain the total revenue requirement.

As shown on page 1 (lines 30-43) of Confidential Exhibit HS-4, under Staff's recommended revenue allocation the Residential class receives 87.2 percent of Staff's proposed increase

[20] TEP Revised Schedule G-1 Inputs line 3
[21] TEP Revised Schedule G-2 line 40

compared to the Company's proposal of 59.7 percent, although Staff's increase is a lesser absolute dollar amount. Under Staff's proposal, all classes receive an increase while the Company's proposal decreased the revenue requirement for the Large Power Service/138kV classes.

This revenue allocation does not follow my general principles in that the Residential and Lighting classes have negative returns and holding to some of my principals would require four rate cases to reach parity.

Q. If Staff's recommended revenue allocation is adopted what will the class returns be?

A. The results of the proposed revenue allocation are forecasted in Confidential Exhibit HS-4. The UROR of the "low UROR" classes (Residential and Lighting) will increase and the UROR of the "high UROR" classes (except the LGS class) will decrease, moving classes towards parity. To decrease the UROR of the LGS class a rate decrease would be needed.

Q. Have some classes been subsidized by other classes in the past?

A. Yes. Confidential Exhibit HS-3 summarizes the Company's latest two CCoSS. In the 2011 CCoSS, the UROR [line 39] is less than 1.0 for the Large General Service class and negative for the Residential, Large Light & Power and Mining classes indicating subsidization by the Small General Service class. In the present CCoSS, the UROR [line 13] is negative for the Residential class. The Lighting class has been negative in both CCoSS.

Q. Please explain why, if the Residential and Lighting classes are being subsidized by other classes, Staff is not recommending class revenue increases to bring those classes to parity, which would be consistent with the rate design plan Staff is recommending and you have detailed above.

A. Staff's plan articulates the concept that "Rates should be based on costs derived from class cost of service studies..."; however, the plan is a long-term plan.

Confidential Exhibit HS-4 shows that to bring the Residential class to parity would require a class revenue increase of 232 percent of the total increase recommended by Staff and an increase of 7 percent of the total increase recommended by Staff for the Lighting class (significantly higher than the Company's proposal). Confidential Exhibit HS-2 demonstrates that significant changes have occurred between the two CCoSS due to the impacts of the acquisition of a portion of Gila River Unit No. 3 and the changes in various allocators.

As explained above, revenue allocation is not just an algorithm-based process but it is tempered by a Commission's evaluation of other factors. Also, Staff's recommendation to move the Residential class towards removing the subsidy allows for the completion of the process in following cases.

Q. Does Staff's revenue allocation reflect the late breaking (June 6, 2016) confidential information about a significant customer?

A. No. On June 6th the Company provided information on the expected partial closure of a significant customer. This information included "initial projection of the changes to" annual billing determinants (demand and energy) by rate schedule but did not include the breakdown by season or time of use. "The Company expects to make an adjustment in its Rebuttal filing to reduce billing determinants to reflect the known and measureable reduction in sales to this customer."

Because the billing determinants were only initial projections and not complete, Staff has not made an estimate of the impact on each class of this still unfolding event. Staff has discussed with the Company a list of information that it expects to need to evaluate this emerging situation. At this time, Staff has not determined its position on the event or the revenue or rate implications.

RATE DESIGN

Q. Please summarize the Company's rate design proposal.

A. The Company's rate design objectives are "To align rate structures with our customers' evolving energy use", "To reduce the level of cross-subsidies between customers" and "To give the Company an appropriate opportunity to recover its fixed costs."[22]

The Company has focused on the use of a three-part rate design (customer, demand and energy charges) that would be mandatory for all new DG customers[23] and optional for other RES and SGS customers.[24] The Company suggests that these changes are to better align the Commission's policies with the Company's need for fixed cost recovery and system usage.[25] The Company is also supporting gradualism when making rate design changes.[26] For new DG customers, the Company is proposing monthly bill credits for any excess energy delivered to the Company's system.[27]

[22] Hutchens Direct 11:23 – 12:16
[23] Hutchens Direct 18:22, Dukes Direct 8:18
[24] Dukes Direct 24:3
[25] Hutchens Direct 20:1
[26] Hutchens Direct 23:26
[27] Hutchens Direct 24:9

Q. What was the Company's primary concern in developing its rate design proposals?

A. As I understand the Company's approach, the focus is the recovery of fixed costs. A concern is expressed that seasonal customers, vacant homes or businesses, and DG customers (with their associated low kWh consumption) limit the Company's ability to recover fixed costs.[28]

Q. Is this focus on fixed costs sufficient to support rate design changes?

A. Yes. If fixed costs are not properly accounted for in the rate design, intra-class subsidies will occur. The challenge is how to and how fast to make the changes. RES and SGS customers have a simple rate design and even the acceptance of TOU rates in these classes has been limited.[29] With new rate forms, some customers need education and support to achieve a meaningful transition.

Q. Is the Company's unit cost analysis in Schedule G-6-1 Revised useful in evaluating its proposed Basic Service Charges?

A. The Company's information shows direct customer costs, an amount that includes meters, billing and collection, meter reading costs and the service line or drop. The Company has indicated that it used a minimum-sized system to allocate portions of the distribution system (such as poles, wires, transformers) to the customer component.[30] These costs are included in the customer-related unit costs.

[28] Dukes Direct 11:10
[29] Schedule H-2 approximately 2.3% of residential customers
[30] TEP Response to STF 1.38 and STF 1.32

Q. What changes does the Company propose for the Residential Electric Service (Rate RES) rate?

A. **The Company** is requesting an increase in the Basic Service Charge from $10.00 to $20.00.[31] Energy charges also are proposed to increase,[32] and the Company is proposing to eliminate the third and fourth tiers because the tiers are being used for fixed cost recovery.[33]

Q. What changes does the Company propose for the Residential Time-of-Use (Rate RES-TOU) rate?

A. The Company is requesting an increase in the Basic Service Charge from $11.50 to $20.00 for TOU customers,[34] and the addition of a second tier to match the configuration of the RES rate.[35]

Q. What are the residential customer costs?

A. The Company's information shows that customer costs are $17.19.[36] This amount includes meters, billing and collection, meter reading costs and the service (line or drop) and the components that form the minimum-sized system.

Q. What changes does Staff recommend to the proposed RES residential rate?

A. Staff recommends the following modifications of the Company's proposal:

- The existing third and fourth tiers should be eliminated and the remaining inclination should be flattened as the residential customer's load factor increases as usage increases, which does not support inclined rates.[37]

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[31] Jones Direct 43:9 and 43:27
[32] TEP Schedule H-3
[33] Jones Direct 45:1
[34] TEP Schedule H-3
[35] Jones Direct 45:15
[36] TEP Revised Schedule G-6-1 line 24

- All residential Basic Service Charges should be $17.00 to approximate the Company's costs. With the advent of AMI, residential customers will be using the same meter and therefore have the same costs.

- The revenue allocated to the Residential class should be collected first by an increase in the Basic Service Charge up to the level proposed here, with the remainder (if any) recovered by increased energy charges to begin to levelize the tiers. Applying the revenue increase to the Basic Service Charge first and eliminating the third and fourth tiers will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

Q. What is the impact on residential customers of Staff's recommendations?

A. Based upon Staff's recommended overall increase in revenue requirements along with its revenue allocation and rate design changes, the average residential RES customers would see an increase of $6.96 per month or an 8 percent increase as shown in Exhibit HS-5 page 1.

Q. What changes does the Company propose for the SGS rate?

A. For SGS customers, the Company is requesting an increase in the Basic Service Charge from $16.50 and $17.50 (TOU) to $30.00.[38] The energy charges also are proposed to increase.[39] This non-demand class will be limited to customers with a maximum energy consumption of 24,000 kWh accumulated across two consecutive months.[40] The unit cost information in Schedule G-6-1 indicates that customer costs for the SGS Class are $38.43.[41]

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[37] Dukes Direct 25:1
[38] Jones Direct 46:23
[39] TEP Schedule H-3, Page 12
[40] Jones Direct 47:1
[41] TEP Revised Schedule G-6-1 line 24

Q. What changes does Staff recommend to the SGS rate?

A. Staff recommends the following modifications of the Company's proposal:

- The Basic Service Charge should be $26.80, this amount was determined to meet the reduced revenue requirements for the General Service class.

- The revenue allocated to the SGS class should be collected first by an increase in the Basic Service Charge up to the level proposed by the Company, with the remainder (if any) recovered by increased energy charges. Applying the revenue increase to the Basic Service Charge first will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

- The Company's proposal to move a customer to the new MGS rate "if the customer's consumption meets or exceeds 24,000 kWh in consecutive months" is appropriate as it does not penalize a customer for a single usage excursion.

Q. What is the impact on small general service customers of Staff's recommendations?

A. Based upon Staff's recommended overall increase in revenue requirements along with its revenue allocation and rate design changes, general service SGS customers would see increases as shown in Exhibit HS-5 page 2.

Q. The existing RES and SGS rates are not Three-Part-TOU rates and therefore are not in accordance with the Staff's long-term rate design plan. What do you recommend for an initial step?

A. Staff recommends that the Commission approve in this proceeding optional Three-Part-TOU rates for RES and SGS customers. As customers gain experience with these optional rates

and see their demand on their monthly bills, the Commission can consider other steps in the Company's next rate case.

Q. The Company is proposing the Residential Electric Service Demand (RES-D), Residential Electric Service Time-of-Use Demand (RES TOU-D), Small General Service Demand (SGS-D) and Small General Service Time-of-Use Demand (SGS TOU-D) rates. Do these rates meet Staff's rate design concepts?

A. The Company has not defined the source of the various values and tiers within the proposed demand rates. Also, the demand charge will apply to all time periods. The Company has not explained the theory and background of these rates, and the Company should provide more support in its rebuttal testimony. At present without this information, Staff does not support these rates for any purpose.

Q. What is the Company's proposal for a new MGS rate?

A. The Company wants to establish a new MGS rate for existing Small and Large General Service ("LGS") customers with demand between 20 kW and 250 kW.[42] This rate class will have the same demand measurement and ratchet as the existing LGS class.[43] The Company is requesting a Basic Service Charge of $40.00. Demand charges are proposed to be $7.00 per kW summer and $5.00 per kW winter.[44] The Company is proposing that any customer that exceeds the 250 kW cap "for a billing month will be automatically moved, in the subsequent month to the new LGS rate class. The customer must remain there for at least 12 months without exceeding the 250 kW demand to qualify to move back to MGS."[45]

[42] Jones Direct 37:19 and 43:25
[43] Jones Direct 38:1 and 49:3
[44] TEP Schedule H-3, Page 15
[45] Jones Direct 47:10

Q. Is the Company's proposal to create a new MGS class and MGS rate schedule appropriate?

A. Conceptually, yes. Creating rate classes based on demand (and voltage) is appropriate. However, the Company has indicated that the transition of almost 4,000 SGS customers from the existing non-demand rate to the MGS rate which will include demand charges and a demand ratchet may have adverse impacts for a number of those customers. The Company's filing provides no information about these customers and the impact of the new MGS rate on them. Staff has requested further details about the support and education to be provided to these customers.[46] The Company has indicated that once the particulars of the new rate (along with more recent usage) have been determined the Company will contact customers that appear to have increases above normal. Potential MGS customers were not provided specific notice of the specific proposed change. Staff conceptually supports the establishment of the MGS class subject to further details about the Company's plans for notice and the education and support program. The Company should address in its rebuttal this significant change for the MGS customers.

Q. Is the Company's proposed customer charge for MGS customers appropriate?

A. The unit cost information in Revised Schedule G-6-1 indicates that customer costs for the SGS and LGS Classes respectively $38.43 and $536.17.[47] Unfortunately, the unit costs were not differentiated for the MGS rate class.

Q. What changes does Staff recommend to the MGS rate?

A. Staff recommends the following modifications of the Company's proposal:

- The three-part rate design is appropriate as it reflects Staff's long-term rate design.

[46] TEP Response to STF 20.08
[47] TEP Revised Schedule G-6-1 line 24

- The $40.00 Basic Service Charge requested by the Company may be too low in light of the mixed CCoSS. However, as a transition this situation is acceptable.

- The ratchet provision proposed for the new MGS rate should be delayed because the Company has not provided detailed information on the impact of the creation of this new rate schedule on the almost 4,000 customers who at present are not subject to a demand charge and demand ratchet.

- The Company's proposal that "any customer exceeding the cap for a billing month will automatically be moved, in the subsequent month, to the new LGS rate class", is abrupt and too short a period to determine if the move is appropriate, nor has the impact been determined. Absent further information, Staff does not support this "one-chance" provision and suggests the Company address this issue in its rebuttal testimony.

- The Company should develop and implement a Medium General Service cost of service class in its next rate case to verify the costs to be used in the future MGS rate design.

Q. Is there some risk when significant rate design changes are made?

A. Yes. Rate design changes may have unintended results for "outlier" or "non-normal" MGS customers that do not fit neatly into their apparent customer class. The imposition of a demand ratchet (if approved) may also have unforeseen impacts. These risks are increased when customer notice and outreach is limited or has not been performed.

Staff recommends, as provided for in the previous TEP settlement (Docket No. E-01933A-12-0291), the Commission should keep the rate design portion of this rate case open for at

least 18 months after the completion of the transition to MGS rates to account for unanticipated customer rate impacts that are determined to be inconsistent with the public interest.

Q. What changes does the Company propose for the LGS rate?

A. For LGS rate customers, the Company is requesting an increase in the customer charge from $775.00 and $950.00 (TOU) to $1,000.00. Demand charges are proposed to increase from $15.25 to $17.50 per kW.[48] This class will retain the existing a minimum demand of 200 kW, and there will be a demand eligibility cap of 5,000 kW above which the customer will be moved to the LPS-TOU class.[49]

Q. Is the Company's increase in the customer charge for LGS customers appropriate?

A. The unit cost information in Revised Schedule G-6-1 indicates that customer costs for the Large General Service Class are $536.17.[50]

Q. What changes does Staff recommend to the LGS rate?

A. Staff recommends the following modifications of the Company's proposal:

- The three-part rate design is appropriate as it retains the existing rate structure.
- The Basic Service Charge should remain at its present level, as the charge requested by the Company is not supported by the unit costs.
- The revenue allocated to the LGS rate should be collected first by an increase in the demand charge, with the remainder (if any) recovered by increased energy charges.

[48] TEP Schedule H-3, Page 19
[49] Jones Direct 47:14
[50] TEP Schedule G-6-1 line 24

Applying the revenue increase to the demand charge first and then to energy charges will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

- The proposal to impose a maximum demand of 5,000 kW has not been supported in the Company's filing. Absent support indicating the number of customers affected and the extent of the impact, Staff does not support this provision and suggests the Company address this issue in its rebuttal testimony.

Q. What rate changes does the Company propose for the LPS customer class?

A. For LPS rate customers, the Company is requesting no change in the $2,000 Basic Service Charge. The summer On-Peak Demand charge is proposed to decrease from $20.49 to $18.00 per kW.[51] This demand class will continue to have a minimum demand of 3,000 kW.[52] It is important to note that there will only be a TOU rate for LPS customers.[53]

Q. Is the Company's no change in the Basic Service Charge for Large Power Service customers appropriate?

A. The unit cost information in Revised Schedule G-6-1 indicates that customer costs for the Large Power Service Class are $17,490.91.[54] The difference between the proposed Basic Service Charge and the customer costs is substantial and should be explained by the Company in its rebuttal.

Q. What changes does Staff recommend to the LPS rate?

A. Staff recommends the following modifications of the Company's proposal:

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[51] TEP Schedule H-3, Page 18
[52] Jones Direct 48:2
[53] Jones Direct 47:19
[54] TEP Response to STF 2.057, Line 23

- The three-part rate design is appropriate as it retains the existing rate structure.
- The Basic Service Charge should move toward a cost based rate subject to the Company's rebuttal information.
- The revenue allocated to the LPS rate should be collected first by an increase in the Basic Service Charge, with the remainder (if any) recovered by increased demand and then energy charges. Applying the revenue increase to the Basic Service Charge first and then to demand charges will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

Q. Is the Company's proposal for a new 138 kV rate appropriate?

A. The Company is proposing a new 138kV TOU rate for customers able and willing to take service at transmission level voltages. The Company is proposing a Basic Service Charge of $3,000, demand charges of $17.15 and $12.49 per kW (summer and winter respectively) and a minimum demand of 10,000 kW. These rates are similar to the LPS rates.[55] Schedule H-1 shows no customers on this rate, while Revised Schedule G-2 indicates one customer on the rate. While the Company has provided specific details on the development of portions of this rate[56], it has not provided enough information to render an opinion on the Basic Service Charge and other elements. Staff suggests the Company address this issue in its rebuttal testimony.

Q. What changes is the Company proposing for the Lighting Service rate?

A. The Company is proposing a 46 percent increase in certain lighting charges[57] in order to raise the performance of this underperforming class.[58] The wattage charge does not define

[55] Jones Direct 53:20
[56] Jones Direct 54:17
[57] TEP Schedule H-3
[58] Jones Direct 49:17

whether it is solely the lamp wattage or if a ballast load is included.[59] Staff suggests the Company address this issue in its rebuttal testimony.

Q. Does Staff agree with the rate changes that the Company has proposed for the Lighting Service rate?

A. Revised Schedule G-1 indicates the Lighting class has a return of -13.61 percent compared to a total system return of 5.52 percent.[60] After the Company's proposed increase the class will still have a negative return.[61] Due to the existing very negative return of the Lighting class it may take several cases to move the Lighting class towards parity with the other rate classes. Consistent with Staff's revenue allocation for the Residential class, Staff is proposing an increase of $1.377 million[62] for the Lighting class as compared to the Company's proposed $1.246 million increase[63].

Interruptible Rates

Q. Please describe the Company's interruptible rate proposals?

A. Based on the Company's testimony[64] and the tariff sheet provided, the Company is not proposing any significant changes in existing interruptible Rider-12.

Lifeline

Q. Please describe the Company's proposal for Lifeline customers?

A. In its last rate case, the Company began a transition to the inclusion of Lifeline customers on existing residential rates but with a fixed Lifeline discount. Under this concept, Lifeline customers can easily determine their discount and the impact on their bills if their financial

[59] Exhibit CAJ-4 Schedule LTG
[60] TEP Revised Schedule G-1, line 36
[61] TEP Revised Schedule G-2, line 35
[62] Staff Confidential Exhibit HS-4, page 1, line 36
[63] Staff Confidential Exhibit HS-4, page 4, line 6
[64] Jones Direct 57:3

situation were to improve. The existing $9.00 Lifeline discount for these Lifeline customers is simple to understand and administer.[65] However, there are still legacy Lifeline customers (some dating from the mid 1990s with substantial discounts) and there are multiple configurations of the Lifeline discount (27).[66] The Company is proposing to increase the discount to $15.00 and further consolidate the 27 rates to five available to new and existing customers and 5 that would apply to existing customers.[67] For existing frozen Lifeline rate customers, the Company is proposing to use a flat monthly $15 discount[68] from the standard residential rates and in some cases also reduce the Basic Service Charge in order to approximate the existing subsidies and limit the increase to an amount similar to non-Lifeline customers.[69]

Q. What is the value/cost of the Lifeline discounts?

A. The Company estimates the discounts totaled $1,798,110 during the Test Year for nearly 15,000 Lifeline customers.[70]

Q. Does Staff support the Lifeline proposal?

A. In keeping with Staff's long-term plan for rate design, the Staff supports the Company's Lifeline proposal subject to a few concerns.

- The impact on Lifeline customers of any rate change is dependent on the level of residential rate change and the structure of the residential rates. Staff recommends that the validation of the Lifeline impact and the required discounts be performed after the revenue allocation and residential rate design is finalized.

[65] Jones Direct 58:10
[66] Jones Direct 58:15
[67] Jones Direct 57:20
[68] Jones Direct 57:26
[69] Jones Direct 59:3
[70] Jones Direct 58:4

- The Company should "prove out" that the level of Lifeline discounts after the finalized changes in rates is at or above the Test Year value.

- The roster of Lifeline customers should be examined, and any existing Lifeline customer who would be better off (on an annual basis) on the flat monthly discount should be moved to the new Lifeline discount rate.

Distributed Generation

Q. Is the Company proposing that all DG customers move to a three part rate?

A. Yes. The Company argues that DG customers are partial requirements customers and the existing two-part rate design is inappropriate for this service.[71]

Q. Should residential DG customers be moved to the Residential Electric Service Demand (Res-D) or Residential Time-of-Use Demand (RES TOU-D) rate at the close of this case as requested by the Company?

A. No. Consistent with Staff's long-term rate design plan, the actions taken behind the meter of any customer are not the sole determinant of which rate the customer must use. Staff is awaiting the Commission's decisions in the UNS case (15-0142) and the Value and Cost of Distributed Generation case (14-0023) and may update its position on the appropriate rate for DG customers in rebuttal or later at hearing.

Q. What is the Company's proposal for excess energy produced by distributed generation and fed back into the Company's system?

A. The Company has proposed a new net metering rider that allows customers with DG to sell monthly excess energy production to the Company at the Renewable Credit Rate.[72] This

[71] Dukes Direct 5:8
[72] Dukes Direct 4:26 and Tilghman Direct 10:13

proposal would apply to all customers who submitted a completed application after June 1, 2015,[73] while existing DG customers (and applications submitted before June 1, 2015) would stay on the current rider for up to 20 years from the date of approval.[74]

Q. Does the Company's proposal eliminate the banking option for new DG customers?

A. Yes. The Company proposes to pay for energy received with a monthly bill credit.[75]

Q. How is the Renewable Credit Rate ("RCR") defined?

A. The Company proposes a RCR of 5.84 cents per kWh, which it argues is equivalent to the most recent utility scale renewable energy purchased power agreement connected to the distribution system. The project in question is due for completion in 2015.[76]

The Company indicates that it would file an annual RCR update similar to the existing Market Cost of Comparable Conventional Generation when it makes its annual REST filing based on the most recent comparable utility scale purchased power agreement for renewable energy.[77]

Q. Is a utility scale photovoltaic facility a reasonable proxy for the value of energy provided by photovoltaic DG?

A. The Company argues that a utility scale photovoltaic facility is a reasonable proxy for photovoltaic DG because it has similar production characteristics (seasonality, time of day and response to weather). If the procurement of the utility scale energy is from one or more independent suppliers, then the resulting price is a reasonable estimate of the market value at

[73] Dukes Direct 4:21 and Tilghman Direct 10:20
[74] Dukes Direct 4:23
[75] Dukes Direct 4:27
[76] Tilghman Direct 9:14
[77] Tilghman Direct 10:6

that approximate location at that point in time and for the period of the Purchase Power Agreement ("PPA").

Excess energy from a photovoltaic DG installation is not entirely representative of a utility scale PV facility because the DG customer is providing the net output equal to the photovoltaic output less any energy consumed by the customer and therefore may have a delivery profile different from a utility scale facility.

Q. Did the Company perform a system loss study?

A. Yes. The Company provided a summary of its detailed loss study[78] (classified as competitively sensitive) that is based on identifying different stages in the transmission and distribution system including transformer losses.

Q. Should the purchase price for excess DG energy be adjusted for losses?

A. Yes. Most of the energy the Company generates or purchases should be assumed to transit the Company's transmission system, and for most customers the Company's distribution system. A portion of the energy consumed by a distribution customer is lost from the point of generation to the ultimate customer. Since it is likely that energy is provided by a DG customer to nearby neighbors, losses should be added to the RCR. Based on the Company's loss study summary losses could be substantial (value not included due to confidentiality).

Q. What other potential savings and costs are due to the existence of DG?

A. There may be savings in transmission charges; however, the Company has not addressed this issue. Other parties to this case may be able to add to the record in this area.

[78] CONFIDENTIAL TEP Response to STF 1.35

Some participants may consider savings from deferred or avoided distribution investment. In the on-going UNS case, the Company has identified a TEP substation[79] as a possible preferred location for the installation of solar generation along with supporting technologies. If DG can be shown to defer or eliminate required distribution investment, DG customers that provide the needed "support" should receive a locational adder.

Q. Does Staff have a recommendation as to how to determine the value of excess energy?

A. It is early in this rate case proceeding and many interested parties have not yet filed their positions on the value of excess energy. Commission Docket No. E-00000J-14-0023, which is intended to examine the value and cost of DG, will continue to provide useful information to the parties in this rate case. Therefore, for the time being, Staff does not propose any changes to the existing net metering tariff or waivers of the net metering rules but it may update its position in its Surrebuttal testimony or later at the hearing in this case.

Staff does oppose the Company's reliance on a single Purchased Power Agreement to establish the RCR and also opposes at this time any change in net metering absent the adoption of three-part rates, subject to decisions in the Commission's value and cost of DG docket.

Staff notes that in the various cases at this time that the Company and solar industry interveners propose that existing DG solar customers as of a specified date be "grandfathered". During those proceedings, Staff has offered a number of proposals intended to mitigate the impact on existing solar customers. Staff is not necessarily opposed to some form of grandfathering as a mitigation factor, but is concerned that any form of grandfathering must clearly define the elements of the current rate design that are included in

[79] UNS Response to STF 2.034

grandfathering (such as basic service and energy charges which change after each rate case), establish a fair and reasonable date for delineating which DG customers are grandfathered, define how long a facility is grandfathered based on lifespan or other factors such as return on investment, and not impede the Commission's ability to address rates for these customers in the future. The decision should also close the window on future grandfathering of newer vintage facilities and allow future Commissions the ability to revisit grandfathering at each subsequent rate case.

Service Fee Changes

Q. Please describe the changes proposed by the Company to the TEP Electric Statement of Charges?

A. The table below details the changes the Company is proposing. The Company is requesting a new charge for Consumption History Request and Interval History Request on an hourly basis:[80]

[80] Exhibit CAJ-3 Original Sheet 801 and Jones Direct 70:9

Description	Existing Rate	TEP's Proposed Rate
Service Transfer Fee	$20.00	$26.00
Customer-Related Meter Re-read	$20.00	$26.00
Special Meter Reading Fee (including Customer Self-Reads)	$20.00	$26.00
Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures During Regular Business Hours – Single-Phase Service	$32.00	$38.00
Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures After Regular Business Hours (includes Saturdays, Sundays and Holidays) – Single-Phase Service	$57.00	$61.00
Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures During Regular Business Hours – Three-Phase Service	$78.00	$129.00
Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures After Regular Business Hours (includes Saturdays, Sundays and Holidays) – Three-Phase Service	$216.00	$271.00
Service Reestablishment under other than usual operating procedures (including Automated Meter Opt-Out Set-Up Fee) – Single Phase Service	$150.00	$187.00
Single-Phase Line Extension Charge per Foot	$17.00	$17.00
Three-Phase Line Extension Charge per Foot	$27.00	$27.00
Underground Differential Line Extension Charge per Foot	$21.00	$21.00
PME Switchgear Cabinet	$20,500.00	$20,500.00
Meter Test	$186.00	$211.00
Returned Payment Fee	$10.00	$10.00
Late Payment Finance Charge	1.5%	1.5%
Residential Solar – Company Owned Program Processing Fee	$250.00	$250.00
Consumption History Request and Interval History Request	----	$65.00 an hour

Q. What did you find during your review of the cost support data for these charges?

A. The Company provided a worksheet detailing the underlying costs for each of these charges.[81] The information provided supports the Company's request except as detailed below.

[81] UDR 1.001 2015 TEP Service Fees.xlsx

Q. What did you find during your review of the cost support data for the Service Establishment after Regular Business Hours Three Phase charge?

A. The Service Establishment – Regular Business Hours Three Phase entails 1 hour of a Metering Journeymen compared to performing the work after hours using 2 hours of a TEP Lineman. The Company should explain why a Lineman is used for the after hours work when a TEP Metering Journeyman can perform the task After Hours – Single Phase for 1.5 hours. The data would indicate that a TEP Metering Journeyman is available after hours and may have different work rules.

Q. What other concerns do you have with the Consumption History Request and Interval History Request charge?

A. There appears to be some confusion as to when this charge will be applied. The Company states this charge will apply only after the first time a customer requests interval data, but this is not clear on the Statement of Charges.[82] Also, this charge should not apply if the Company develops a means to allow customers to look up or request their usage information online or through a mobile application that does not require the work of an employee. Finally, Staff recommends that this charge not apply to MGS customers for a period of six months after the mandatory transition of MGS customers.

Q. Is the inclusion of Automated Meter Opt-Out Set-Up within the classification of Service Reestablishment under other than usual operating conditions appropriate?

A. No. The proposed charge of $187 for the Automated Meter Opt-Out Set-Up Fee has been set assuming "other than usual operating procedures". Changing the meter for an Opt-Out customer, which entails setting a digital meter that does not transmit data wirelessly, does not have to be done as a special event and can be scheduled during normal working hours.

[82] Jones Direct 74:20

Therefore, the charge should be the proposed $38 for Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures During Regular Business Hours to reflect this situation.

Buy-Through

Q. Please describe the Experimental Rider 14 "Buy-Through" proposal submitted by the Company?

A. The Company was required to introduce the "Buy-Through" as a result of a settlement during the merger process,[83] but the Company does not support this tariff change.[84]

Q. What is the Staff position on the "Buy-Through"?

A. Because the Company is not supporting this concept, there is no record describing the benefits to non-participating customers. Staff does not object to a "Buy-Through" mechanism if there are no adverse impacts and no costs to all other customers. Staff is concerned that Buy-Through customers may return when the market becomes tight (expensive) and thus impact customers that did not or could take advantage of the Buy-Through provisions. Staff opposes recouping any allegedly lost Buy-Through revenue and likewise opposes any deferral of allegedly lost Buy-Through revenue. This opposition to recouping lost incremental revenues extends to the use of the LFCR for that purpose.[85]

Staff looks forward to reviewing testimony in support of the "Buy-Through" by other parties.

[83] Jones Direct 61:18
[84] Jones Direct 61:23
[85] Jones Direct 80:4

AMI Opt-Out

Q. What is the AMI Opt-Out?

A. Some customers have raised concerns about the use of meters that transmit data wirelessly back to the Company. These customers wish to retain their existing mechanical meters, which would then require the Company to read the meter by travelling to the Opt-Out customer's premise, which raises the costs of serving these customers compared to all other customers.

Q. Is the retention of mechanical meters for Opt-Out customers appropriate?

A. No. All customers can benefit from the information provided by AMI meters that record interval data. Mechanical meters cannot provide the data required for, and the potential benefits of, new rate forms and the information that a customer can use to manage their energy usage and intensity.

Q. Is there an alternative that deals with the concerns and provides the interval data for new rate forms?

A. This issue was raised informally with the Company and it suggested a solid-state meter with recording capabilities, which accumulates but does not transmit information.[86] The Company would read the interval data by visiting the customer's premise monthly.

Q. What is Staff's recommendation?

A. If a customer decides to Opt-Out, the Company should install a non-transmitting recording device and read that meter monthly. Because the number of Opt-Out customers is expected to be small and geographically dispersed, the costs of the monthly meter reading should be the Special Meter Reading Fee that requires a premise visit. The costs of the new meter

[86] Email from Brenda Pries dated 11/23/15 at 11:30 AM

installation should be recouped from the customer requesting this non-standard meter (at the proposed $38 for Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures During Regular Business Hours) along with the monthly reading costs (at the proposed $26 Special Meter Reading Fee). Staff will monitor the number of special read customers to determine if the Special Meter Reading Fee remains appropriate as the number of customers using the Opt-Out develops.

Economic Development

Q. Please describe the economic development program proposed by the Company?

A. The Company is proposing an Economic Development Rider 13 ("EDR") for current or potential commercial or industrial customers that meet certain economic development criteria within the Company's service area. The EDR will be available to customers with a projected peak demand of 1,000 kW or more and a load factor of 75 percent or higher. Discounts would decline over a five-year period. New load would be limited to 50 MW.[87]

Q. What reasons did the Company provide as support for the EDR program?

A. The Company argues that its service territory has been slow to recover from the economic downturn post 2007.[88]

Q. What are the specific qualifications to obtain the EDR?

A. The EDR qualifications are linked to existing Arizona state tax credit programs, which appear to be designed to create new in-state above median wage jobs with healthcare benefits.[89]

[87] Dukes Direct 31:9
[88] Dukes Direct 30:3
[89] Dukes Direct 31:20

Q. What levels of discount are offered?

A. For economic development (requires the building of new facilities), the discount starts at 20 percent and declines to 2.5 percent. For economic redevelopment (occupying vacant facilities), the discount starts at 30 percent and declines to 5 percent.[90]

Q. How will the discounts be recouped?

A. The Company's proposal did not address this issue. Staff explored this question in a data request. The Company responded that most of the revenues will reduce incremental revenues between rate cases, and will not be included in a cost of service analysis. The Company expects to include these additional customers and/or loads in any future rate proceedings by applying the applicable retail rate when establishing test year adjusted revenues. Therefore, no subsidy or discount will be allocated to any other customer or rate class.[91]

Q. Will existing customers be protected from the impact of new capital expenditures?

A. The Company's proposal did not address this issue. Staff explored this question in a data request. The Company responded that the present rules and regulations approved by the Commission governing line extensions and new services would apply equally to these new customers or incremental loads.[92]

Q. At present the Commission is encouraging energy efficiency so isn't the EDR program the direct opposite because it will increase energy sales?

A. Conceptually, electric energy efficiency programs have not focused on limiting the increase in new customers but focused on increasing the efficiency of energy usage. Economic

[90] Dukes Direct 32:6
[91] TEP Response to STF 1.17
[92] TEP Response to STF 1.18

development rates can increase the number of employers, employees and maybe machinery and are expected to provide economic benefits within the utility's service territory. The Company's EDR program is geared towards the reuse of vacant facilities, which have some existing unused (or underused) electrical distribution capacity. Although EDR customers are proposed to be on a standard rate schedule with a discount, if the Commission is concerned about load growth, requirements could be added, such as using only time-of-use rates and/or interruptible service.

Q. What is Staff's recommendation for the EDR?

A. The proposed EDR has limits and is biased towards existing facilities. The Company should address the potential impact of new energy requirements for the incremental load in its rebuttal. Assuming that the energy costs are not significant, then Staff supports this limited (volume and time) program to increase employment in the service territory. Staff's support does not extend to any request for recoupment of the lost incremental revenues absent a supporting record in some future proceeding.

LOST FIXED COST RECOVERY

Q. What purpose does the LFCR mechanism serve?

A. The LFCR mechanism, as approved by the Commission, serves to compensate the Company between rate cases for the revenue lost by the Company's compliance with established requirements for EE and DG.

Q. What is your experience with the LFCR mechanism in Arizona?

A. On behalf of Staff, I sponsored the LFCR mechanism in the Arizona Public Service ("APS") rate case (Docket No. E-01345A-11-0224), the TEP rate case (Docket No. E-01933A-12-0291) and the last UNSE rate case (Docket No. E-04204-12-0504).

Q. What has been the impact of the LFCR mechanism on the Company's customers?

A. "The combined EE and DG surcharge from the first TEP LFCR filing was approximately 0.7 percent and the 2015 LFCR filing resulted in approximately a 0.4 percent incremental increase for a total adjustment of approximately 1.1 percent."[93]

Q. Please describe the Company's LFCR proposal in this proceeding.

A. The Company's LFCR proposal is to change the established LFCR mechanism to increase the revenue recovered due to the effects of energy efficiency and distributed generation.[94]

Q. What is the revenue impact of the Company's proposed changes to the LFCR mechanism?

A. The Company estimates the impact of the recovery of generation costs and 100 percent of the demand costs to be approximately $13,000,000.[95] "However, based on the data supporting the 2015 LFCR filing, the Company estimates that the incremental LFCR increase for including generation costs would have incrementally increased the total LFCR adjustment by an additional 1.7 percent to a total adjustment of 2.8 percent."[96]

Q. What changes is the Company proposing that will affect the presentation on the customer's bill?

A. Presently, the utility is required to show the EE and DG components of the LFCR mechanism on the bill as two separate items. The Company is proposing to combine the two items into a single line item.[97]

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[93] Jones Direct 80:23
[94] Jones Direct 77:22
[95] Jones Direct 78:19
[96] Jones Direct 80:27
[97] Jones Direct 80:10

The Company is also asking for permission to no longer offer the Fixed Cost Option in the LFCR mechanism.[98]

Q. What portions of the Company's proposal to modify the LFCR mechanism do you recommend that the Commission accept?

A. I support the Company's proposal to remove the Fixed Cost Option from the LFCR because no customer has used that option at the Company[99] or at the Company's affiliate UNS[100].

Q. What portions of the Company's proposal to modify the LFCR mechanism do you recommend that the Commission not accept?

A. The Commission should not accept the proposals that will increase the revenue impact on customers including:

- Allowing the Company to receive recovery for generation costs
- Increasing the recovery for distribution demand costs from 50 percent to 100 percent
- Increasing the cap on recovered costs allowed for each year from 1 percent to 2 percent
- Using the LFCR to recoup lost revenues resulting from any Alternate Generation Services ("Buy Through")

Further, the Commission should not accept the change proposed by the Company to combine the EE and DG portions of the mechanism on the customer's bill as that provision was originally implemented by the Commission[101] and serves to highlight for the customer the relative impacts of EE and DG, which affect different customer subclasses.

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[98] Jones Direct 79:18
[99] Jones Direct 79:19
[100] UNS Filing 15-0142 Jones Direct 77:15
[101] July 11, 2013, Open Meeting

Q. Why should the Commission reject including generation and purchased power in the LFCR mechanism?

A. Purchased power is fungible and is not affected if energy is delivered to a new customer, an existing customer using slightly more energy, an economic development customer or sold off-system. Therefore, the Company has many opportunities to adjust its energy supply. Further, the impact of this change would more than double the effect of the LFCR.

Q. What is the Company's forecast for sales?

A. The Company's Firm Load Obligations (System Coincident Peak Demand (MW)) shows increasing requirements in Net Retail Demand (which is net of DG and EE).[102] The load forecast shows a trend of increasing total numbers of customers[103] and the reference case (without the effects of EE and DG) shows increasing sales to retail customers.[104] The Company's Firm Wholesale Requirements are also forecasted to increase starting in 2017.[105]

The Company has released its 2016 Preliminary Integrated Resource Plan. The Preliminary 2016 IRP is forecasting continued increases in the number of customers.[106] The weather normalized Retail Energy Forecast indicated "While use per customer is expected to remain weak over the near term, the largest impact on near-term sales is the anticipated curtailment of copper mining operations recently announced by TEP's largest retail customer." And "After 2020, sales growth is dominated by residential and commercial sales but at a pace below historical average."[107] "... [peak] demand is expected to drop in 2016. This is largely attributed to the mining class. Afterward, TEP's retail peak demand is expected to grow over

[102] TEP 2014 Integrated Resource Plan Table 4 (page 28)
[103] TEP 2014 Integrated Resource Plan Chart 10 (page 49)
[104] TEP 2012 Integrated Resource Plan Chart 12 (page 52)
[105] TEP 2014 Integrated Resource Plan Table 6 (page 56)
[106] TEP 2016 Preliminary Integrated Resource Plan Chart 3 (page 26)
[107] TEP 2016 Preliminary Integrated Resource Plan Chart 5 (page 28)

time."[108] After a decrease from 2017 to 2018, firm wholesale requirements are expected to rise through 2021.[109] Table 3, which includes the reductions in load due to the impact of distributed generation and energy efficiency, indicates increasing Total Retail Customers, Residential Sales Growth, Commercial Sales Growth, Retail Demand.[110]

Q. Could the proposed EDR and the Company's LFCR changes create a situation where some generation could be double collected?

A. Yes. The Company is proposing an economic development rate in this case that if successful would increase energy sales, peak demand and revenue. In an unusual twist, if the Company's proposal to include generation in the LFCR mechanism is approved, the Company could bill existing customers for the generation costs within the LFCR mechanism, redirect the generation (energy and capacity) to a new customer attracted by the proposed economic development rates and effectively double collect on that load.

Q. Why should the Commission reject increasing from 50 percent to 100 percent the distribution demand component in the LFCR mechanism?

A. Distribution costs are not as fungible and some distribution assets cannot serve other customers within the short term. Therefore, a reduction in per customer sales may result in a shortfall in revenues to cover distribution fixed costs. The LFCR adopted by the Commission provides a mechanism to recapture the portion of distribution costs that are collected on a volumetric (per kWh) basis. Some of the Company's rate schedules collect distribution costs using demand charges, which will remain constant or change slower than a straight volumetric rate.

[108] TEP 2016 Preliminary Integrated Resource Plan Chart 7 (page 29)
[109] TEP 2016 Preliminary Integrated Resource Plan Table 2 (page 30)
[110] TEP 2016 Preliminary Integrated Resource Plan Table 3 (page 31)

Q. Why should the Commission reject increasing from 1 percent to 2 percent the cap in the LFCR mechanism?

A. If the Commission does not accept the Company's proposed changes to the LFCR, then the increase in the cap is not necessary.

Q. Why should the Commission reject using the LFCR mechanism to recoup lost revenues resulting from Alternate Generation Service ("Buy Through")?

A. Alternate Generation Service is not available to all customers and it appears that the benefits would flow through to those customers able to use "Buy Through". It would be inappropriate to charge all customers for benefits that accrue primarily to a select few customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Direct Testimony of Howard Solganick
Docket No. E-01933A-15-0322
Exhibit HS-1

Testimony - Howard Solganick

Arizona Corporation Commission
Case – UNS Electric Docket No. E-00000J-14-00023 (February 2016)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered the value and cost of distributed generation and other related issues.

Case – UNS Electric Docket No. E-04204A-15-0142 (November 2015 and December 2015)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered cost of service, revenue allocation, rate design, revenue decoupling and other related issues.

Case – UNS Electric Docket No. E-04204A-12-0504 (June 2013 and July 2013)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Case – Tucson Electric Power Company Docket No. E-01933A-12-0291 (December 2012 and January 2013)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Case – Arizona Public Service Company Docket No. E-01345A-11-0224 (November and December 2011)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Public Service Commission of Delaware
Case - Delmarva Power & Light Company Docket No. 10-237 (October 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and miscellaneous charges.

Case - Delmarva Power & Light Company Docket No. 09-414 (February 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and weather normalization.

Case - Delmarva Power & Light Company Docket No. 09-277T (November 2009)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered an analysis of a straight fixed variable rate design for small gas customers and implementation issues.

Case - Delmarva Power & Light Company Docket No. 06-284 (January 2007)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization or normalization.

Georgia Public Service Commission
Case – Atlanta Gas Light Company Docket No. 31647 (August 2010)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered revenue forecast, cost of service, revenue allocation, rate design and other related issues.

Case – Atmos Energy Corporation Docket No. 27163 (July 2008)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered rate design and other related issues.

Jamaica (West Indies) Office of Utility Regulation
Case - Electricity Appeals Tribunal (August 2007)
Client - Jamaica Public Service Company, Ltd.
Scope - "Witness Statement" on behalf of the Jamaica Public Service Company Limited. This Statement covered issues relating to recovery of expenses incurred due to Hurricane Ivan.

Maine Public Utilities Commission
Case - Northern Utilities, Accelerated Cast Iron Replacement Program Docket No. 2005-813 (2005)
Client - Public Advocate of the State of Maine
Scope - Testimony covered an analysis of the program's economics and implementation.

Public Service Commission of Maryland
Case - Chesapeake Utilities Corporation Case No. 9062 (August 2006)
Client - Office of the Maryland People's Counsel
Scope - Testimony covered cost of service, rate design and other related issues.

Case - Baltimore Gas & Electric's (1993)
Client - As president of the Mid Atlantic Independent Power Producers
Scope - Testimony covered BG&E's capacity procurement plans.

Michigan Public Service Commission
Case - Consumers Energy Company Case No. U-15245 (November 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered cost of service, rate design and revenue allocation.

Case - Consumers Energy Company Case No. U-15190 (July 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy's gas revenue decoupling proposal.

Case - Consumers Energy Company Case No. U-15001 (June 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy and the MCV Partnership.

Case - Consumers Energy Company Case No. U-14981 (September 2006)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues relating to the sale of Consumers interest in the Midland Cogeneration Venture.

Case - Consumers Energy Company Case No. U-14347 (June 2005)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope – Testimony covered cost of service and revenue allocation.

Missouri Public Service Commission
Case – AmerenUE Storm Adequacy Review (July 2008)
Client – KEMA/AmerenUE
Scope – Oral testimony covered KEMA's review of AmerenUE's system major storm restoration efforts.

Case – Veolia Energy Kansas City, Inc. File No. HR-2011-0241 (September 2011)
Client – City of Kansas City, Missouri
Scope – Testimony covered various aspects of the Company's tariff provisions and the impact on the City of Kansas City.

New Jersey Board of Public Utilities
Case - Cogeneration and Alternate Energy Docket # 8010-687 (1981)
Case - PURPA Rate Design and Lifeline Docket # 8010-687 (1981)
Case - Atlantic Electric Rate Case - Phases I & II Docket # 822-116 (1982)
Case - Power Supply Contract Litigation – Wilmington Thermal Systems Docket # 2755-89 (1989)
Case - NJBPU Atlantic Electric Rate Case - Phase II (1980-81) Docket # 7911-951 (Before the Commissioners of the New Jersey Board of Public Utilities)
Client - Employer was Atlantic City Electric Company.
Scope - The cases listed above covered load forecasting, capacity planning, load research, cost of service, rate design and power procurement.

Public Utilities Commission of Ohio
Case - The Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company Case 07-551-EL-AIR (January 2008)
Client - Ohio Schools Council
Scope - Testimony covers issues related to rate treatment of schools.

Case - The Application of the Columbus Southern Power Company 08-917-EL-SSO and the Ohio Power Company Case 08-918-EL-SSO (October 2008)
Client - Ohio Hospital Association
Scope - Testimony covers issues related to rates for net metering and alternate feed service and related treatment of hospitals.

Pennsylvania Public Utilities Commission
Case - York Water Company Docket No. R-00061322 (July 2006)
Client - Pennsylvania Office of Consumer Advocate
Subject - Testimony covered cost of service, rate design and other related issues, also supported the settlement process.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2010)
Client – Municipal Sewer Group
Subject - Testimony covered capacity planning, construction, treatment of future load and associated revenue, cost of service, rate design, capacity fee and other related issues.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2008)
Client – Municipal Sewer Group
Subject - Testimony covered cost of service, rate design, capacity fee and other related issues, also supported the settlement process.

Public Utilities Commission of Texas
Case – Determination of Hurricane Restoration Costs Docket No. 36918 (April 2009)
Client – CenterPoint Energy Houston Electric, LLC
Subject – Testimony covered the reasonableness of the client's Hurricane Ike restoration process for an outage covering over two million customers and a restoration period of 18 days

LINE	CCoSS Comparisons	A	B	C	D	[redacted]	G
	2015 CCoS Classes	TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE SMALL	LARGE GENERAL SERVICE		LIGHTING
	2011 CCoS Classes	TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE		LIGHTING
1	**Total Intangible Plant**						
2	2015 CCoS	$160,246,771	$92,285,178	$33,712,632	$16,278,713		$1,437,572
3	% of Total 2015	1.000	0.576	0.210	0.102		0.009
4	2011 CCoS	$95,706,208	$46,410,743	$19,856,966	$11,432,151		$4,926,836
5	% of TOTAL	1.000	0.485	0.207	0.119		0.051
6	% Change 2015 vs. 2011	67.4%	98.8%	69.8%	42.4%		-70.8%
7	Ratio 1						
8	Ratio 2						
9							
10	**Accumulated Depreciation - Intangible Plant**						
11	2015 CCoS	$119,977,698	$69,094,454	$25,240,846	$12,187,968		$1,076,319
12	% of Total 2015	1.000	0.576	0.210	0.102		0.009
13	2011 CCoS	$61,094,680	$29,626,599	$12,675,823	$7,297,788		$3,145,077
14	% of TOTAL	1.000	0.485	0.207	0.119		0.051
15	% Change 2015 vs. 2011	96.4%	133.2%	99.1%	67.0%		-65.8%
16	Ratio 1						
17	Ratio 2						
18							
19	**Net Intangible Plant**						
20	2015 CCoS	$40,269,073	$23,190,724	$8,471,787	$4,090,745		$361,253
21	% of Total 2015	1.000	0.576	0.210	0.102		0.009
22	2011 CCoS	$61,094,680	$29,626,599	$12,675,823	$7,297,788		$3,145,077
23	% of TOTAL	1.000	0.485	0.207	0.119		0.051
24	% Change 2015 vs. 2011	-34.1%	-21.7%	-33.2%	-43.9%		-88.5%
25	Ratio 1						
26	Ratio 2						
27							
28							
29							
30	**Total Production Plant**						
31	2015 CCoS	$2,080,992,837	$1,073,843,310	$466,579,966	$256,045,939		$1,826,258
32	% of Total 2015	1.000	0.516	0.224	0.123		0.001
33	2011 CCoS	$1,638,020,642	$793,047,554	$340,438,186	$209,658,321		$13,205,137
34	% of TOTAL 2011	1.000	0.484	0.208	0.128		0.008
35	% Change 2015 vs. 2011	27.0%	35.4%	37.1%	22.1%		-86.2%
36	Ratio 1						
37	Ratio 2						
38							
39	**Accumulated Depreciation - Production Plant**						
40	2015 CCoS	$796,297,495	$410,909,025	$178,538,076	$97,976,666		$698,823
41	% of Total 2015	1.000	0.516	0.224	0.123		0.001
42	2011 CCoS	$764,915,641	$370,333,842	$158,976,320	$97,905,316		$6,166,476
43	% of TOTAL	1.000	0.484	0.208	0.128		0.008
44	% Change 2015 vs. 2011	4.1%	11.0%	12.3%	0.1%		-88.7%
45	Ratio 1						
46	Ratio 2						
47							
48	**Net Production Plant**						
49	2015 CCoS	$1,284,695,342	$662,934,285	$288,041,889	$158,069,273		$1,127,436
50	% of Total 2015	1.000	0.516	0.224	0.123		0.001
51	2011 CCoS	$873,105,001	$422,713,712	$181,461,866	$111,753,005		$7,038,660
52	% of TOTAL	1.000	0.484	0.208	0.128		0.008
53	% Change 2015 vs. 2011	47.1%	56.8%	58.7%	41.4%		-84.0%
54	Ratio 1						
55	Ratio 2						
56							
57							
58							
59	**Distribution**						
60	**Total Distribution Plant**						
61	2015 CCoS	$1,441,783,351	$954,902,876	$274,539,855	$101,816,282		$29,776,532
62	% of Total 2015	1.000	0.662	0.190	0.071		0.021
63	2011 CCoS	$1,243,492,787	$604,282,700	$257,413,460	$134,539,804		$135,131,561
64	% of TOTAL	1.000	0.486	0.207	0.108		0.109
65	% Change 2015 vs. 2011	15.9%	58.0%	6.7%	-24.3%		-78.0%
66	Ratio 1						
67	Ratio 2						
68							
69	**Accumulated Depreciation- Distribution**						
70	2015 CCoS	$579,194,987	$382,375,665	$108,264,696	$42,054,488		$13,376,247
71	% of Total 2015	1.000	0.660	0.187	0.073		0.023
72	2011 CCoS	$524,017,237	$252,347,477	$109,006,084	$57,438,334		$57,969,714
73	% of TOTAL	1.000	0.482	0.208	0.110		0.111
74	% Change 2015 vs. 2011	10.5%	51.5%	-0.7%	-26.8%		-76.9%
75	Ratio 1						
76	Ratio 2						
77							
78	**Net Distribution Plant**						
79	2015 CCoS	$862,588,364	$572,527,211	$166,275,158	$59,761,794		$16,400,285
80	% of Total 2015	1.000	0.664	0.193	0.069		0.019
81	2011 CCoS	$719,475,551	$351,935,222	$148,407,376	$77,101,470		$77,161,847
82	% of TOTAL	1.000	0.489	0.206	0.107		0.107
83	% Change 2015 vs. 2011	19.9%	62.7%	12.0%	-22.5%		-78.7%
84	Ratio 1						
85	Ratio 2						
86							

LINE CCoSS Comparisons

		A	B	C	D	[redacted]	G
	2015 CCoS Classes	TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE SMALL	LARGE GENERAL SERVICE		LIGHTING
	2011 CCoS Classes	TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE		LIGHTING
87	**Total General Plant**						
88	2015 CCoS	$314,077,737	$180,875,530	$86,075,511	$31,905,674		$2,817,588
89	% of Total 2015	1.000	0.576	0.210	0.102		0.009
90	2011 CCoS	$222,233,554	$107,767,559	$46,108,651	$26,545,902		$11,440,305
91	% of TOTAL	1.000	0.485	0.207	0.119		0.051
92	% Change 2015 vs. 2011	41.3%	67.8%	43.3%	20.2%		-75.4%
93	Ratio 1						
94	Ratio 2						
95							
96	**Accumulated Depreciation - General Plant**						
97	2015 CCoS	$88,548,234	$49,842,621	$18,207,972	$8,792,027		$776,423
98	% of Total 2015	1.000	0.576	0.210	0.102		0.009
99	2011 CCoS	$61,611,122	$29,877,037	$12,782,974	$7,359,477		$3,171,663
100	% of TOTAL	1.000	0.485	0.207	0.119		0.051
101	% Change 2015 vs. 2011	40.5%	66.8%	42.4%	19.5%		-75.5%
102	Ratio 1						
103	Ratio 2						
104							
105	**Net General Plant**						
106	2015 CCoS	$227,529,503	$131,032,909	$47,867,538	$23,113,648		$2,041,165
107	% of Total 2015	1.000	0.576	0.210	0.102		0.009
108	2011 CCoS	$160,622,433	$77,890,522	$33,325,677	$19,186,425		$8,268,641
109	% of TOTAL	1.000	0.485	0.207	0.119		0.051
110	% Change 2015 vs. 2011	41.7%	68.2%	43.6%	20.5%		-75.3%
111	Ratio 1						
112	Ratio 2						
113							
114							
115							
116	**Total Electric Plant in Service**						
117	2015 CCoS	$3,997,100,696	$2,301,906,895	$840,907,964	$406,046,589		$35,857,951
118	% of Total 2015	1.000	0.576	0.210	0.102		0.009
119	2011 CCoS	$3,199,453,192	$1,551,508,556	$663,817,262	$382,176,178		$164,703,838
120	% of TOTAL	1.000	0.485	0.207	0.119		0.051
121	% Change 2015 vs. 2011	24.9%	48.4%	26.7%	6.2%		-78.2%
122	Ratio 1						
123	Ratio 2						
124							
125							
126	**Total Accumulated Depreciation**						
127	2015 CCoS	$1,582,018,414	$912,221,765	$330,251,591	$161,011,129		$15,927,812
128	% of Total 2015	1.000	0.577	0.209	0.102		0.010
129	2011 CCoS	$1,411,638,679	$682,184,956	$293,441,200	$170,000,916		$70,452,931
130	% of TOTAL	1.000	0.483	0.208	0.120		0.050
131	% Change 2015 vs. 2011	12.1%	33.7%	12.5%	-5.3%		-77.4%
132	Ratio 1						
133	Ratio 2						
134							
135							
136	**Total Net Plant in Service**						
137	2015 CCoS	$2,415,082,282	$1,389,685,129	$510,656,373	$245,035,460		$19,930,139
138	% of Total 2015	1.000	0.575	0.211	0.101		0.008
139	2011 CCoS	$1,787,814,513	$869,323,600	$370,376,062	$212,175,262		$94,250,907
140	% of TOTAL	1.000	0.486	0.207	0.119		0.053
141	% Change 2015 vs. 2011	35.1%	59.9%	37.9%	15.5%		-78.9%
142	Ratio 1						
143	Ratio 2						
144							

LINE	CCoSS Comparisons	A	B	C	D	[redacted]	G
	2015 CCoS Classes	TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE SMALL	LARGE GENERAL SERVICE		LIGHTING
	2011 CCoS Classes	TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE		LIGHTING
145	**Expenses**						
146	**Total Production Expense**						
147	2015 CCoS	$421,678,184	$189,441,644	$91,112,246	$65,231,386		$1,459,547
148	% of Total 2015	1.000	0.449	0.216	0.155		0.003
149	2011 CCoS	$475,802,168	209,998,747	107,228,213	63,736,243		2,685,042
150	% of TOTAL	1.000	0.441	0.225	0.134		0.006
151	% Change 2015 vs. 2011	-11.4%	-9.8%	-15.0%	2.3%		-45.2%
152	Ratio 1						
153	Ratio 2						
154							
155	**Transmission**						
156	2015 CCoS	$95,464,952	$49,262,255	$21,404,223	$11,746,034		$83,779
157	% of Total 2015	1.000	0.516	0.224	0.123		0.001
158	2011 CCoS	$90,028,056	$43,587,075	$18,710,990	$11,523,134		$725,774
159	% of TOTAL	1.000	0.484	0.208	0.128		0.008
160	% Change 2015 vs. 2011	6.0%	13.0%	14.4%	1.9%		-88.5%
161	Ratio 1						
162	Ratio 2						
163							
164	**Total Distribution Expenses**						
165	2015 CCoS	$24,085,317	$16,319,423	$4,409,813	$1,553,987		$568,559
166	% of Total 2015	1.000	0.678	0.183	0.065		0.024
167	2011 CCoS	$22,965,413	$10,697,159	$5,009,944	$2,507,307		$2,656,260
168	% of TOTAL	1.000	0.466	0.218	0.109		0.116
169	% Change 2015 vs. 2011	4.9%	52.6%	-12.0%	-38.0%		-78.6%
170	Ratio 1						
171	Ratio 2						
172							
173	**Total Customer Account Expense**						
174	2015 CCoS	$21,874,552	$18,486,473	$2,354,053	$256,909		$725,774
175	% of Total 2015	1.000	0.845	0.108	0.012		0.033
176	2011 CCoS	$19,452,377	$16,352,738	$2,201,896	$289,830		$314,063
177	% of TOTAL	1.000	0.841	0.113	0.015		0.016
178	% Change 2015 vs. 2011	12.5%	13.0%	6.9%	-11.3%		131.1%
179	Ratio 1						
180	Ratio 2						
181							
182	**Administration and General Expense**						
183	2015 CCoS	$75,722,484	$66,049,810	$6,582,497	$126,620		$2,960,302
184	% of Total 2015	1.000	0.872	0.087	0.002		0.039
185	2011 CCoS	$65,884,580	$32,766,584	$13,479,222	$8,081,864		$881,638
186	% of TOTAL	1.000	0.497	0.205	0.123		0.013
187	% Change 2015 vs. 2011	14.9%	101.6%	-51.2%	-98.4%		235.8%
188	Ratio 1						
189	Ratio 2						
190							
191	**Total Operations & Maintenance Expense**						
192	2015 CCoS	$638,825,490	$339,559,606	$125,862,831	$78,914,936		$5,797,960
193	% of Total 2015	1.000	0.532	0.197	0.124		0.009
194	2011 CCoS	$674,132,594	$313,402,303	$146,630,266	$86,138,178		$7,242,777
195	% of TOTAL	1.000	0.465	0.218	0.128		0.011
196	% Change 2015 vs. 2011	-5.2%	8.3%	-14.2%	-8.4%		-19.9%
197	Ratio 1						
198	Ratio 2						
199							
200							
201	**501 - FUEL PPFAC Eligible**						
202	2015 CCoS	$303,925,690	128,678,471	64,710,927	50,743,086		1,356,206
203	% of Total 2015	1.000	0.423	0.213	0.167		0.004
204	2011 CCoS	$292,189,698	121,102,785	69,067,097	40,234,780		1,184,824
205	% of TOTAL	1.000	0.414	0.236	0.138		0.004
206	% Change 2015 vs. 2011	4.0%	6.3%	-6.3%	26.1%		14.5%
207	Ratio 1						
208	Ratio 2						
209							

CCoSS Comparisons

		A	B	C	D	[redacted]	G
	2015 CCoS Classes	TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE SMALL	LARGE GENERAL SERVICE		LIGHTING
	2011 CCoS Classes	TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE		LIGHTING
210	**Sales (kWh) G-2**						
211	2015 CCoS	9,020,707,871	3,651,120,932	1,839,512,456	1,477,690,240		38,940,096
212	% of Total 2015	1.000	0.405	0.204	0.164		0.004
213	2011 CCoS	9,332,107,047	3,887,303,965	2,179,138,260	1,222,821,614		37,430,790
214	% of TOTAL	1.000	0.417	0.234	0.131		0.004
215	% Change 2015 vs. 2011	-3.3%	-6.1%	-15.6%	20.8%		4.0%
216	Ratio 1						
217	Ratio 2						
218							
219	**Service Charges (G-2)**						
220	2015 CCoS	5,301,752	4,624,515	460,877	8,865		207,267
221	% of Total 2015	1.000	0.872	0.087	0.002		0.039
222	2011 CCoS	5,112,747	4,423,307	446,993	7,446		234,797
223	% of TOTAL	1.000	0.865	0.087	0.001		0.046
224	% Change 2015 vs. 2011	3.7%	4.5%	3.1%	19.1%		-11.7%
225	Ratio 1						
226	Ratio 2						
227							
228	**Usage per Customer (month)**						
229	2015 CCoS		790	3,991	166,688		188
230	% of Total 2015						
231	2011 CCoS		879	4,875	164,225		159
232	% of TOTAL						
233	% Change 2015 vs. 2011		-10.2%	-18.1%	1.5%		17.9%
234	Ratio 1						
235	Ratio 2						

LINE	CCoSS Comparisons	A	B	C	D	[redacted]	G
	2015 CCoS Classes REVISED (Exhibit G-1)	TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE		LIGHTING
1	**Total Ratebase**	$2,104,677,691	$1,205,895,803	$444,808,100	$214,240,229		$17,302,998
2	% of Total Ratebase		57.3%	21.1%	10.2%		0.8%
3							
4	**Total Operating Revenue**	$958,869,144	$431,971,346	$269,010,674	$114,103,130		$4,966,796
5	% of Total Sales		45.1%	28.1%	11.9%		0.5%
6							
7	**Total Operating Expenses**	$842,650,381	$455,187,352	$169,373,777	$100,248,300		$7,321,251
8	% of Operating Expenses		54.0%	20.1%	11.9%		0.9%
9							
10	**Operating Income**	$116,218,763	-$23,216,006	$99,636,897	$13,854,830		-$2,354,455
11							
12	**Rate of Return**	5.52%	-1.93%	22.40%	6.47%		-13.61%
13	UROR		-0.349	4.057	1.171		-2.464
14							
15	**kWh Sales**	9,020,707,874	3,651,120,932	2,132,332,869	1,177,162,108		38,940,096
16	% of Sales		40.5%	23.6%	13.0%		0.4%
17							
18	**Test Year Adjusted Customers**	441,808.67	385,376.25	38,564.58	577.58		17,272.25
19							
20	**Sales per Customer**		9,474	55,293	2,038,082		
21							
22							
23							
24							
				SMALL	LARGE		
25	**2011 CCoS Classes (Exhibit G-1)**	TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	GENERAL SERVICE		LIGHTING
26							
27	**Total Ratebase**	$1,519,073,362	$738,869,476	$307,503,674	$182,758,071		$82,433,877
28	% of Total Ratebase		48.6%	20.2%	12.0%		5.4%
29							
30	**Total Operating Revenue**	$842,583,379	$379,166,672	$238,207,819	$103,539,944		$4,056,085
31	% of Total Sales		45.0%	28.3%	12.3%		0.5%
32							
33	**Total Operating Expenses**	$813,648,717	$382,116,983	$175,393,746	$102,595,530		$13,480,786
34	% of Operating Expenses		47.0%	21.6%	12.6%		1.7%
35							
36	**Operating Income**	$28,934,662	-$2,950,311	$62,814,073	$944,414		-$9,424,701
37							
38	**Rate of Return**	1.90%	-0.40%	20.43%	0.52%		-11.43%
39	UROR		-0.210	10.724	0.271		-6.002
40							
41	**kWh Sales**	9,332,107,047	3,887,303,965	2,179,138,260	1,222,821,614		37,430,790
42	% of Sales		41.7%	23.4%	13.1%		0.4%
43							
44	**Test Year Adjusted Customers**	426,062.25	368,608.92	37,249.42	620.50		19,566.42
45							
46	**Sales per Customer**		10,546	58,501	1,970,704		
47							
48							
49							
50	**2015 vs 2011**						
51	Increase in Class Ratebase	38.6%	63.2%	44.7%	17.2%		-79.0%
52							
53	Increase in Revenue	13.8%	13.9%	12.9%	10.2%		22.5%
54							
55	Increase in Operating Expenses	3.6%	19.1%	-3.4%	-2.3%		-45.7%
56							
57	Increase in kWh Sales	-3.3%	-6.1%	-2.1%	-3.7%		4.0%
58							
59	Increase in Test Year Adjusted Customers	3.7%	4.5%	3.5%	-6.9%		-11.7%
60							
61	Increase in Sales per Customer		-10.2%	-5.5%	3.4%		

		TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE	<<<<<<CONFIDENTIAL>>>>>>	LIGHTING
		(A)	(B)	(C)	(E)		(H)
	TEP G-1 REVISED						
1	TOTAL OPERATING REVENUE	$958,869,144	$431,971,346	$269,010,674	$114,103,130		$4,966,796
2	TOTAL OPERATING EXPENSES	$842,650,381	$455,187,352	$169,373,777	$100,248,300		$7,321,251
3	OPERATING INCOME	$116,218,763	($23,216,006)	$99,636,897	$13,854,830		($2,354,455)
4							
5	TOTAL RATE BASE	$2,104,677,691	$1,205,895,803	$444,808,100	$214,240,229		$17,302,998
6							
7	RATE OF RETURN ON RATE BASE	5.52%	-1.93%	22.40%	6.47%		-13.61%
8	(ORIGINAL COST RATE BASE)	UROR	-0.349	4.057	1.171		-2.464
9							
10	TEST YEAR ADJUSTED SALES (kWh)	9,020,707,874	3,651,120,932	2,132,332,869	1,177,162,108		38,940,096
11	TEST YEAR ADJUSTED MARGIN REVENUES	605,398,982	275,887,975	184,448,887	68,460,569		3,298,783
12	TEST YEAR ADJUSTED FUEL REVENUES	321,741,284	135,724,786	78,695,943	43,017,444		1,459,034
13	TEST YEAR ADJUSTED SERVICE CHARGES	5,301,705	4,624,515	462,775	6,931		207,267
14							
15	**All UROR = 1.000**						
16	Rate of Return on Rate Base	6.12%	6.12%	6.12%	6.12%		6.12%
17	UROR	1.000	1.000	1.000	1.000		1.000
18							
19	Proposed Sales Revenue	$958,724,672	$519,431,996	$194,741,644	$112,679,505		$8,326,352
20							
21	Change in Margin Revenue	$49,400,000	$114,865,550	($54,418,170)	($8,524,150)		$3,671,360
22	% Change in Margin Revenue	8.2%	41.6%	-29.5%	-9.5%		111.3%
23	% of the Class Change in Margin Revenue	100.0%	232.5%	-110.2%	-13.2%		7.4%
24							
25							
26	Change in Total Revenue	$31,584,406	$107,819,235	($68,403,187)	$1,201,492		$3,568,534
27	% Change in Total Revenue	3.4%	26.2%	-26.0%	1.1%		75.0%
28	% Class Change in Total Revenue	100.0%	341.4%	-216.6%	3.8%		11.3%
29							
30	**37.5% to UROR = 1.000**						
31	Rate of Return on Rate Base	6.12%	0.17%	18.91%	9.72%		-7.14%
32	UROR	1.000	0.028	3.089	1.587		-1.166
33							
34	Proposed Sales Revenue	$958,724,672	$447,641,027	$251,625,319	$120,383,208		$6,031,752
35							
36	Change in Margin Revenue	$49,400,000	$43,074,581	$2,465,505	$1,179,553		$1,376,760
37	% Change in Margin Revenue	8.2%	15.6%	1.3%	1.7%		41.7%
38	% of the Class Change in Margin Revenue	100.0%	87.2%	5.0%	2.4%		2.8%
39							
40							
41	Change in Total Revenue	$31,584,406	$36,028,266	($11,519,512)	$8,905,195		$1,273,934
42	% Change in Total Revenue	3.4%	8.8%	-4.4%	8.0%		26.8%
43	% Class Change in Total Revenue	100.0%	114.1%	-36.5%	28.2%		4.0%

		TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE	<<<<< CONFIDENTIAL >>>>>	LIGHTING
		(A)	(B)	(C)	(E)		(H)
	50% to UROR = 1.000						
1	Rate of Return on Rate Base	6.12%	1.36%	17.25%	8.07%		-4.49%
2	UROR	1.000	0.222	2.818	1.318		-0.733
3							
4	Proposed Sales Revenue	$958,724,672	$461,999,221	$244,243,184	$116,851,429		$6,490,672
5							
6	Change in Margin Revenue	$49,400,000	$57,432,775	($4,916,630)	($2,352,226)		$1,835,680
7	% Change in Margin Revenue	8.2%	20.8%	-2.7%	-3.4%		55.6%
8	% of the Class Change in Margin Revenue	100.0%	116.3%	-10.0%	-4.8%		3.7%
9							
10							
11	Change in Total Revenue	$31,584,406	$50,386,460	($18,901,646)	$5,373,416		$1,732,854
12	% Change in Total Revenue	3.4%	12.2%	-7.2%	4.8%		36.4%
13	% Class Change in Total Revenue	100.0%	159.5%	-59.8%	17.0%		5.5%
14							
15	**45% to UROR = 1.000**						
16	Rate of Return on Rate Base	6.12%	0.88%	17.91%	8.73%		-5.55%
17	UROR	1.000	0.144	2.926	1.426		-0.906
18							
19	Proposed Sales Revenue	$958,724,672	$456,255,944	$247,196,038	$118,264,141		$6,307,104
20							
21	Change in Margin Revenue	$49,400,000	$51,689,498	($1,963,776)	($939,515)		$1,652,112
22	% Change in Margin Revenue	8.2%	18.7%	-1.1%	-1.4%		50.1%
23	% of the Class Change in Margin Revenue	100.0%	104.6%	-4.0%	-1.9%		3.3%
24							
25							
26	Change in Total Revenue	$31,584,406	$44,643,182	($15,948,792)	$6,786,128		$1,549,286
27	% Change in Total Revenue	3.4%	10.8%	-8.1%	6.1%		32.6%
28	% Class Change in Total Revenue	100.0%	141.3%	-50.5%	21.5%		4.9%
29							
30	**40% to UROR = 1.000**						
31	Rate of Return on Rate Base	6.12%	0.41%	18.58%	9.39%		-6.61%
32	UROR	1.000	0.066	3.035	1.534		-1.080
33							
34	Proposed Sales Revenue	$958,724,672	$450,512,666	$250,148,892	$119,676,852		$6,123,536
35							
36	Change in Margin Revenue	$49,400,000	$45,946,220	$989,078	$473,197		$1,468,544
37	% Change in Margin Revenue	8.2%	16.7%	0.5%	0.7%		44.5%
38	% of the Class Change in Margin Revenue	100.0%	93.0%	2.0%	1.0%		3.0%
39							
40							
41	Change in Total Revenue	$31,584,406	$38,899,905	($12,995,939)	$8,198,839		$1,365,718
42	% Change in Total Revenue	3.4%	9.5%	-4.9%	7.4%		28.7%
43	% Class Change in Total Revenue	100.0%	123.2%	-41.1%	26.0%		4.3%

		TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE	<<<<< CONFIDENTIAL >>>>>>	LIGHTING
		(A)	(B)	(C)	(E)		(H)
	35% to UROR = 1.000						
1	Rate of Return on Rate Base	6.12%	-0.07%	19.24%	10.05%		-7.67%
2	UROR	1.000	-0.011	3.143	1.641		-1.253
3							
4	Proposed Sales Revenue	$958,724,672	$444,769,389	$253,101,746	$121,089,564		$5,939,968
5							
6	Change in Margin Revenue	$49,400,000	$40,202,943	$3,941,932	$1,885,909		$1,284,976
7	% Change in Margin Revenue	8.2%	14.6%	2.1%	2.8%		39.0%
8	% of the Class Change in Margin Revenue	100.0%	81.4%	8.0%	3.8%		2.6%
9							
10							
11	Change in Total Revenue	$31,584,406	$33,156,627	($10,043,085)	$9,611,551		$1,182,150
12	% Change in Total Revenue	3.4%	8.1%	-3.8%	8.6%		24.8%
13	% Class Change in Total Revenue	100.0%	105.0%	-31.8%	30.4%		3.7%
14							
15	**33.33% to UROR = 1.000**						
16	Rate of Return on Rate Base	6.12%	-0.23%	19.46%	10.27%		-8.02%
17	UROR	1.000	-0.037	3.179	1.677		-1.311
18							
19	Proposed Sales Revenue	$958,724,672	$442,854,963	$254,086,030	$121,560,468		$5,878,778
20							
21	Change in Margin Revenue	$49,400,000	$38,288,517	$4,926,216	$2,356,813		$1,223,787
22	% Change in Margin Revenue	8.2%	13.9%	2.7%	3.4%		37.1%
23	% of the Class Change in Margin Revenue	100.0%	77.5%	10.0%	4.8%		2.5%
24							
25							
26	Change in Total Revenue	$31,584,406	$31,242,202	($9,058,800)	$10,082,455		$1,120,961
27	% Change in Total Revenue	3.4%	7.6%	-3.4%	9.0%		23.6%
28	% Class Change in Total Revenue	100.0%	98.9%	-28.7%	31.9%		3.5%
29							
30	**30% to UROR = 1.000**						
31	Rate of Return on Rate Base	6.12%	-0.55%	19.91%	10.71%		-8.73%
32	UROR	1.000	-0.089	3.252	1.749		-1.426
33							
34	Proposed Sales Revenue	$958,724,672	$439,026,111	$256,054,599	$122,502,276		$5,756,400
35							
36	Change in Margin Revenue	$49,400,000	$34,459,665	$6,894,785	$3,298,620		$1,101,408
37	% Change in Margin Revenue	8.2%	12.5%	3.7%	4.8%		33.4%
38	% of the Class Change in Margin Revenue	100.0%	69.8%	14.0%	6.7%		2.2%
39							
40							
41	Change in Total Revenue	$31,584,406	$27,413,350	($7,090,231)	$11,024,263		$998,582
42	% Change in Total Revenue	3.4%	6.7%	-2.7%	9.9%		21.0%
43	% Class Change in Total Revenue	100.0%	86.8%	-22.4%	34.9%		3.2%

		TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE	<<<<< CONFIDENTIAL >>>>>	LIGHTING
		(A)	(B)	(C)	(E)		(H)
	TEP G-2						
1	Rate of Return on Rate Base	7.88%	0.92%	19.06%	25.81%		-8.99%
2	UROR	1.000	0.117	2.418	3.274		-1.141
3							
4	Proposed Sales Revenue	$1,018,858,790	$469,968,858	$257,179,598	$157,210,163		$5,900,901
5							
6	Change in Margin Revenue	$109,534,118	$65,402,412	$8,019,784	$38,006,508		$1,245,909
7	% Change in Margin Revenue	18.1%	23.7%	4.3%	55.5%		37.8%
8	% of the Class Change in Margin Revenue	100.0%	59.7%	7.3%	34.7%		1.1%
9							
10							
11	Change in Total Revenue	$91,718,524	$58,356,097	($5,965,232)	$45,732,150		$1,143,083
12	% Change in Total Revenue	9.9%	14.2%	-2.3%	41.0%		24.0%
13	% Class Change in Total Revenue	100.0%	63.6%	-6.5%	49.9%		1.2%
14							
15	**37.5% to UROR = 1.000 (LGS=0.0)**						
16	Rate of Return on Rate Base	6.12%	0.17%	19.08%	9.17%		-7.14%
17	UROR	1.000	0.028	3.117	1.497		(1.166)
18							
19	Proposed Sales Revenue	$958,724,672	$447,641,027	$252,396,906	$119,203,655		$6,031,752
20							
21	Change in Margin Revenue	$49,400,000	$43,074,581	$3,237,092	$0		$1,376,760
22	% Change in Margin Revenue	8.2%	15.6%	1.8%	0.0%		41.7%
23	% of the Class Change in Margin Revenue	100.0%	87.2%	6.6%	0.0%		2.8%
24							
25							
26	Change in Total Revenue	$31,584,406	$36,028,266	($10,747,925)	$7,725,642		$1,273,934
27	% Change in Total Revenue	3.4%	8.8%	-4.1%	6.9%		26.8%
28	% Class Change in Total Revenue	100.0%	114.1%	-34.0%	24.5%		4.0%
29							
30	**Equal Percentage**						
31	Rate of Return on Rate Base	6.12%	-1.58%	21.40%	12.19%		-13.63%
32	UROR	1.000	-0.258	3.496	1.991		-2.227
33							
34	Proposed Sales Revenue	$958,724,672	$426,544,935	$262,695,678	$125,679,517		$4,907,879
35							
36	Change in Margin Revenue	$49,400,000	$21,978,489	$13,535,864	$6,475,861		$252,887
37	% Change in Margin Revenue	8.2%	8.0%	7.3%	9.5%		7.7%
38	% of the Class Change in Margin Revenue	100.0%	44.5%	27.4%	13.1%		0.5%
39							
40							
41	Change in Total Revenue	$31,584,406	$14,932,174	($449,153)	$14,201,504		$150,061
42	% Change in Total Revenue	3.4%	3.6%	-0.2%	12.7%		3.2%
43	% Class Change in Total Revenue	100.0%	47.3%	-1.4%	45.0%		0.5%
44							
45							
46	% Change in Total Revenue	-1.9%	-1.7%	-5.3%	6.9%		-2.2%
47	% Class Change in Total Revenue	100.0%	39.6%	78.5%	-43.4%		0.6%

RESIDENTIAL SERVICE RATE R-01

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05620	$0.06520	$0.07810	$0.08710	$0.031532	$0.00682	
Small	520	500	20	0	0	$10.00	$28.10	$1.30	$0.00	$0.00	$16.40	$3.55	$59.35
Medium	840	500	340	0	0	$10.00	$28.10	$22.17	$0.00	$0.00	$26.49	$5.73	$92.49
Large	1,250	500	500	250	0	$10.00	$28.10	$32.60	$19.53	$0.00	$39.42	$8.53	$138.18
XLg	1,564	500	500	564	0	$10.00	$28.10	$32.60	$44.05	$0.00	$49.32	$10.67	$174.74
AnnAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78
ResAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill		
		500	1000	>1000			500	1000	>1000						
						$17.00	$0.05669	$0.07670	$0.07670		$0.033801	0.0000%		$ Change	% Change
Small	520	500	20	0		$17.00	$28.35	$1.53	$0.00		$17.58	$0.00	$64.46	$5.11	8.6%
Medium	840	500	340	0		$17.00	$28.35	$26.08	$0.00		$28.39	$0.00	$99.82	$7.33	7.9%
Large	1,250	500	500	250		$17.00	$28.35	$38.35	$19.18		$42.25	$0.00	$145.13	$6.95	5.0%
XLg	1,564	500	500	564		$17.00	$28.35	$38.35	$43.26		$52.86	$0.00	$179.82	$5.08	2.9%
AnnAvg	785	500	285	0		$17.00	$28.35	$21.86	$0.00		$26.53	$0.00	$93.74	$6.96	8.0%
ResAvg	785	500	285	0		$17.00	$28.35	$21.86	$0.00		$26.53	$0.00	$93.74	$6.96	8.0%

RESIDENTIAL SERVICE RATE R-01

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05620	$0.06720	$0.07980	$0.08820	$0.035111	$0.00682	
Small	822	500	322	0	0	$10.00	$28.10	$21.64	$0.00	$0.00	$28.86	$5.61	$94.21
Medium	1,384	500	500	384	0	$10.00	$28.10	$33.60	$30.64	$0.00	$48.59	$9.44	$160.37
Large	1,997	500	500	997	0	$10.00	$28.10	$33.60	$79.56	$0.00	$70.12	$13.62	$235.00
XLg	2,430	500	500	1,430	0	$10.00	$28.10	$33.60	$114.11	$0.00	$85.32	$16.57	$287.70
AnnAvg	785	500	285	0	0	$10.00	$28.10	$19.15	$0.00	$0.00	$27.56	$5.35	$90.16
ResAvg	1,150	500	500	150	0	$10.00	$28.10	$33.60	$11.97	$0.00	$40.38	$7.84	$131.89

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill		
		500	1000	>1000			500	1000	>1000						
						$17.00	$0.05669	$0.07670	$0.07670		$0.037325	0.0000%		$ Change	% Change
Small	822	500	322	0		$17.00	$28.35	$24.70	$0.00		$30.68	$0.00	$100.73	$6.52	6.9%
Medium	1,384	500	500	384		$17.00	$28.35	$38.35	$29.45		$51.66	$0.00	$164.81	$4.44	2.8%
Large	1,997	500	500	997		$17.00	$28.35	$38.35	$76.47		$74.54	$0.00	$234.71	-$0.29	-0.1%
XLg	2,430	500	500	1,430		$17.00	$28.35	$38.35	$109.68		$90.70	$0.00	$284.08	-$3.62	-1.3%
AnnAvg	785	500	285	0		$17.00	$28.35	$21.86	$0.00		$29.30	$0.00	$96.51	$6.35	7.0%
ResAvg	1,150	500	500	150		$17.00	$28.35	$38.35	$11.51		$42.92	$0.00	$138.13	$6.24	4.7%

Small General Service RATE GS-10

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.05700	$0.07900	$0.031532	$0.00682	
Xsm	190	190	0	$15.50	$10.83	$0.00	$5.99	$1.30	$33.62
Small	687	500	187	$15.50	$28.50	$14.77	$21.66	$4.69	$85.12
Medium	1,744	500	1,244	$15.50	$28.50	$98.28	$54.99	$11.89	$209.16
Large	3,680	500	3,180	$15.50	$28.50	$251.22	$116.04	$25.10	$436.36
XLg	5,157	500	4,657	$15.50	$28.50	$367.90	$162.61	$35.17	$609.68
AnnAvg	1,568	500	1,068	$15.50	$28.50	$84.37	$49.44	$10.69	$188.50
SGSAvg	1,340	500	840	$15.50	$28.50	$66.36	$42.25	$9.14	$161.75

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
				$26.80	$0.06200	$0.08300	$0.033801	0.0000%		$ Change	% Change
Xsm	190	190	0	$26.80	$11.78	$0.00	$6.42	$0.00	$45.00	$11.38	33.8%
Small	687	500	187	$26.80	$31.00	$15.52	$23.22	$0.00	$96.54	$11.42	13.4%
Medium	1,744	500	1,244	$26.80	$31.00	$103.25	$58.95	$0.00	$220.00	$10.84	5.2%
Large	3,680	500	3,180	$26.80	$31.00	$263.94	$124.39	$0.00	$446.13	$9.77	2.2%
XLg	5,157	500	4,657	$26.80	$31.00	$386.53	$174.31	$0.00	$618.64	$8.96	1.5%
AnnAvg	1,568	500	1,068	$26.80	$31.00	$88.64	$53.00	$0.00	$199.44	$10.94	5.8%
SGSAvg	1,340	500	840	$26.80	$31.00	$69.72	$45.29	$0.00	$172.81	$11.06	6.8%

Small General Service RATE GS-10

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.07700	$0.09780	$0.035111	$0.00682	
Xsm	216	216	0	$15.50	$16.63	$0.00	$7.58	$1.47	$41.18
Small	882	500	382	$15.50	$38.50	$37.36	$30.97	$6.02	$128.35
Medium	2,354	500	1,854	$15.50	$38.50	$181.32	$82.65	$16.05	$334.02
Large	4,820	500	4,320	$15.50	$38.50	$422.50	$169.24	$32.87	$678.61
XLg	6,690	500	6,190	$15.50	$38.50	$605.38	$234.89	$45.63	$939.90
AnnAvg	1,568	500	1,068	$15.50	$38.50	$104.45	$55.05	$10.69	$224.19
SGSAvg	1,886	500	1,386	$15.50	$38.50	$135.51	$66.21	$12.86	$268.58

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
				$26.80	$0.07700	$0.09800	$0.037325	0.0000%		$ Change	% Change
Xsm	216	216	0	$26.80	$16.63	$0.00	$8.06	$0.00	$51.49	$10.31	25.0%
Small	882	500	382	$26.80	$38.50	$37.44	$32.92	$0.00	$135.66	$7.31	5.7%
Medium	2,354	500	1,854	$26.80	$38.50	$181.69	$87.86	$0.00	$334.85	$0.83	0.2%
Large	4,820	500	4,320	$26.80	$38.50	$423.36	$179.91	$0.00	$668.57	-$10.04	-1.5%
XLg	6,690	500	6,190	$26.80	$38.50	$606.62	$249.70	$0.00	$921.62	-$18.28	-1.9%
AnnAvg	1,568	500	1,068	$26.80	$38.50	$104.67	$58.53	$0.00	$228.50	$4.31	1.9%
SGSAvg	1,886	500	1,386	$26.80	$38.50	$135.79	$70.38	$0.00	$271.47	$2.89	1.1%

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239

PUBLIC SURREBUTTAL

RATE DESIGN TESTIMONY

OF

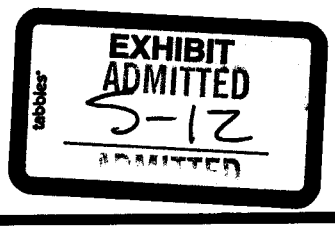
HOWARD SOLGANICK

FOR THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 26, 2016



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EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NOS. E-01933A-15-0239 AND E-01933A-15-0322

Mr. Solganick's surrebuttal rate design testimony reviews the Tucson Electric Power Company ("TEP" or "Company") rebuttal testimony including the revised billing determinants related to the partial closure of the Company's largest customer.

Using the proposed settlement revenue requirements recommendation of $81,500,000, Mr. Solganick provides the Staff recommendation for the allocation of Staff's recommended rate increase among the six major rate classes.

Based on a review of TEP's application and recent updates and consistent with Staff's long-term rate design plan, Mr. Solganick provides proposed rate schedules using Staff's prior recommendations for the rate design for each of TEP's rate classes including recommendations for Lifeline. The rate impact of Staff's proposed rate design is provided.

Staff also addresses various parties' proposals for the Buy-Through provision and TEP's Lost Fixed Cost Recovery mechanism rebuttal.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Howard Solganick. I am a Principal at Energy Tactics & Services, Inc. My business address is 810 Persimmon Lane, Langhorne, PA 19047. I am performing this assignment under subcontract to Blue Ridge Consulting Services, Inc. ("Blue Ridge").

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("Commission").

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. I have testified and/or presented testimony (summarized in Exhibit HS-1) before the following regulatory bodies:

- Arizona Corporation Commission
- Delaware Public Service Commission
- Georgia Public Service Commission
- Jamaica (West Indies) Electricity Appeals Tribunal
- Maine Public Utilities Commission
- Maryland Public Service Commission
- Michigan Public Service Commission
- Missouri Public Service Commission
- New Jersey Board of Public Utilities
- Public Utilities Commission of Ohio
- Pennsylvania Public Utility Commission
- Public Utility Commission of Texas

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I previously provided testimony relating to cost of service, revenue allocation, rate design, and the Lost Fixed Cost Recovery ("LFCR") mechanism on June 24, 2016. My initial testimony in this case includes a summary of my background, qualifications, and experience.

Q. What is the purpose of your surrebuttal rate design testimony?

A. My testimony provides a portion of Staff's response to rebuttal testimony filed by the Company along with direct testimony filed by some of the interveners.

Q. Please summarize Staff's positions introduced in your prior testimony in this case.

A. Staff recommended:

Long-Term Rate Design Plan

Over the long term, rates should be based on costs and recognize the concepts of customer, demand and energy, including time-of-use ("TOU"). When changes are made, gradualism should be recognized.

Class Cost of Service Study

The purposes of a Class Cost of Service Study ("CCOSS") were discussed, along with changes in the Company's CCOSS including a new production cost methodology.

Revenue Allocation

Staff recommended a revenue allocation among the customer classes based on moving all classes toward cost of service, but recognizing that gradualism is necessary due to the effects of a new production cost methodology and the Company's inclusion into rate base of a portion of the new Gila River Unit #3.

Rate Design

Staff recommended rate designs for each rate schedule, consistent with the long-term rate design plan. Staff recommended the implementation of optional Three Part-TOU rates for residential and small general service ("SGS") rates customers and a requirement that the

Company begin to provide demand information for non-demand rate residential and SGS customers. Staff also highlighted areas where the Company should provide further information and justification for its proposals.

Staff highlighted that, due to the implementation of the proposed Medium General Service ("MGS") rate class, the Commission should keep the rate design portion of the case open to resolve unanticipated customer rate impacts.

Miscellaneous Items

- Lifeline – Staff recommended that the level of this discount not be reduced and that the transition of these customers to standard residential rates with the addition of a single discount for Lifeline be implemented.
- Distributed Generation ("DG") – Staff noted that Commission Docket No. E-00000J-14-0023, which is intended to examine the value and cost of DG, will continue to provide useful information to the parties in this rate case. Therefore, Staff did not propose any changes to the existing net metering tariff or waivers of the net metering rules, but may update its position at the hearing in this case.
- Service Fee Charges – Staff analyzed the Company's proposals and recommends which fees should apply to Opt-Out customers.
- Buy-Through – Staff looked for the input of other parties and does not object to this mechanism if there are no adverse impacts and no costs to other customers.
- Economic Development – Staff supports the establishment of the program, but does not support any request for lost revenues.

LFCR

Based on a review of the Company's application and testimony, Staff recommended that the Commission reject the Company's proposed changes to the LFCR mechanism that include:

- Allowing the Company to receive recovery for generation costs;
- Increasing the recovery for distribution demand costs from 50 percent to 100 percent;
- Increasing the cap on recovered costs allowed for each year from 1 percent to 2 percent;
- Expanding the LFCR mechanism to include revenues lost from an Alternate Generation or "Buy-Through" provision to be established in the Company's tariff; and
- Combining the Energy Efficiency ("EE") and DG portions of the mechanism on the customer's bill.

SURREBUTTAL TESTIMONY

Q. What is Staff's focus for this surrebuttal testimony?

A. Staff provides its recommended revenue allocation and rate design reflecting the $81,500,000 revenue requirements in the proposed Settlement Agreement and the update provided by the Company in its rebuttal testimony. Staff addresses the Company's request to recognize changes in billing determinants due to the partial closure of the Company's largest customer. Staff also analyzes proposals by various parties concerning the "Buy-Through" provision, along with a response to the Company's comments on the LFCR.

REVENUE ALLOCATION

Q. What non-cost considerations should the Commission consider during its deliberations on revenue allocation?

A. The Commission should consider the relative starting positions (from the CCOSS) of the classes, along with the qualitative issues such as economic conditions for consumers, the business climate for commercial and industrial customers, and past practices when deciding what portion of a revenue increase is allocated to each class in this case.

Q. What principles do you generally use to allocate revenue among rate classes?

A. I have used the following principles:

- The individual rate classes should be gradually moved toward a Unitized Rate of Return ("UROR") of 1.000 over one or more rate cases depending on the frequency of rate cases and the distance of the class' UROR from 1.000.
- There should be an upper bound of 150 percent for any class' percentage increase in revenue compared to the overall percentage increase in revenue.
- There should be a lower bound of 50 percent for any class' increase compared to the overall increase.

Q. Are there other concepts that apply in this case?

A. The purchase of the Gila River combined cycle generating unit was intended to stabilize energy costs, which provides benefits to all customers. Therefore, it would be inappropriate to reduce rates for any customer class because that would send a confusing message about the new plant expenditure.

Q. Please provide a high level summary of the updated CCOSS provided by the Company in its rebuttal.

A. The Company has provided an updated CCOSS that incorporates either oversights made by the Company in its Direct Testimony or changes suggested by parties to which the Company can agree. The Company also included adjustments to reflect major usage reductions by the Company's largest customer.[1] Subsequent to that update on August 12, 2016, the Company provided its response to STF 31.11 which included a confidential version of its CCOSS that continued to reflect its revenue request prior to the completion of the settlement process for revenue requirements.

The updated CCOSS[2] results show several notable changes:

- Unlike the previous revised CCOSS, there are no classes with a negative return.
- Using the UROR as an indicator, the Residential class has a UROR of 0.083, Large General Service ("LGS") class has a UROR of 0.480 and Lighting class has a UROR of 0.414, all falling below the overall rate of return for the Total Company (UROR of 1.000) at 6.28 percent.
- The General Service ("GS") class has a UROR of 3.309 and the Large Power Service ("LPS") class (including the customer making up the Transmission Service 138 kV class) has an approximate UROR of 1.948.
- Although the Company has requested that a new MGS class be established, it is not shown as a separate class, unlike the Company's proposed Transmission Service 138 kV class, which the Company did model.

[1] Jones Rebuttal 5:13
[2] STF 31.11 Schedule G-1

Q. Please summarize the Company's updated Schedule G-2, which reflects its proposed revenue allocation for the $100.6 million increase?

A. Schedule G-2 indicates the following:

- The overall rate of return for the Company increases from 6.28 percent to 7.90 percent.
- The UROR for the Residential class increases from 0.083 to 0.367.
- The UROR for the GS class decreases from 3.309 to 2.039.
- The UROR for the LGS class increases from 0.480 to 2.481.
- The UROR of the LPS class decreases from 1.948 to 0.837 (below the overall rate of return).
- The UROR of the Transmission Service 138 kV class is now [redacted].
- The UROR of the Lighting class increases from 0.414 to 1.003.

Q. Please summarize the Company's updated Schedule G-6-1, which derives unit costs?

A. Schedule G-6-1 indicates (from prior CCOSS) the following:

- The unit cost for a Residential Customer has decreased from $17.19 to $15.62.
- The unit cost for a GS customer has increased from $38.43 to $39.45.
- The unit cost for a LGS customer has increased from $536 to $640.
- The unit cost for a LPS customer has increased from $17,490 to $22,162.
- The unit cost for a Residential customer's distribution demand has decreased from $6.92 to $6.44/kW.
- The unit cost for a GS customer's distribution demand has increased from $3.40 to $3.57/kW.

- The unit cost for a LGS customer's distribution demand has increased from $2.45 to $2.72/kW.
- The unit cost for a LPS customer's distribution demand has increased from $2.95 to $3.27/kW.

With the reduced sales due to reduced operation by a large Customer, the Company revised the allocators in the latest CCOSS which changed a number of the values highlighted above.[3] These changes have implications on rate design as Staff's prior rate design was based on different unit costs.

Q. Have some of the parties reached a settlement on revenue requirements?

A. Yes. I have been informed that Staff, the Company and other parties have reached a settlement for an increase in revenue requirements of $81.5 million.

Q. Have you modeled various revenue allocations based on Staff's recommended revenue requirements?

A. Exhibit HS-6 models the Settlement revenue increase a number of ways. For comparison purposes the increase was allocated:

- Equal percentage increase (across the board by revenue);
- Moving all of the classes to the same return (UROR equals 1.000);
- Moving the Residential, LGS and Lighting classes 50 percent of the amount needed to reach parity (and increase all other classes by $ 23.3 million);
- Moving the Residential, LGS and Lighting classes 70 percent of the amount needed to reach parity (and increase all other classes by $ 0.07 million);
- Moving the Residential, LGS and Lighting classes 65 percent of the amount needed to reach parity (and increase all other classes by $ 5.9 million);
- Moving the Residential, LGS and Lighting classes 60 percent of the amount needed to reach parity (and increase all other classes by $ 11.7 million);

[3] STF 31.07

- Moving the Residential, LGS and Lighting classes 55 percent of the amount needed to reach parity (and increase all other classes by $ 17.5 million);
- Moving the Residential, LGS and Lighting classes 45 percent of the amount needed to reach parity (and decrease all other classes by $ 29.1 million);
- Moving the Residential, LGS and Lighting classes 40 percent of the amount needed to reach parity (and increase all other classes by $ 35 million);
- Moving the Residential, LGS and Lighting classes 35 percent of the amount needed to reach parity (and increase all other classes by $ 40.8 million);
- Moving the Residential, LGS and Lighting classes 30 percent of the amount needed to reach parity (and increase all other classes by $ 46.6 million).

The remaining revenue requirements from the other classes (GS, LPS and 138kV) were allocated based on their respective expected revenues (Test Year Adjusted Margin Revenues[4] plus Test Year Proposed Fuel Revenues[5]).

Q. In your direct testimony you noted that there was late breaking confidential information about a significant customer.[6] Has that information been detailed in the Company's rebuttal testimony?

A. A review of the rebuttal testimony provided by Company witnesses does not find a detailed discussion of the impact of this event. Exhibit CAJ-R-3 page 2 (Schedule H-2) does show that the Company has reduced Total Company sales (kWh) from 9,020,707,874 (Test Year Adjusted) to 8,882,011,173 (Proposed) for a reduction in kWh sales of 138,696,701.

Q. How is this change in sales delineated in other schedules?

A. Schedule H-1 defines the various changes by class, but this specific change is not noted separately because Schedule H-2 is a public schedule and there is a need to preserve the usage of a single customer for privacy and competitive reasons. Table 1 on page three of Company witness Dukes' rebuttal testimony does not delineate this change, also apparently for privacy

[4] STF 31.11 Schedule G-1 Inputs line 3
[5] STF 31.11 Schedule G-2 line 40
[6] Solganick Direct 26:19

reasons. There are some changes within the revenue requirements calculations due to allocations. The STF 31.11 CCOSS reflects the decrease in kWh sales and changes in allocations.

Q. What is the magnitude of the revenue value of the sales reduction?

A. On a confidential file[7] the location of the change in sales can be isolated [redacted]

[redacted]

Q. For the purposes of demonstrating the rate impacts in this case, how is Staff handling the sales reduction?

A. Subject to the Company's responses to the above questions, and the Commission's decision on the issue, for purposes of demonstrating the rate impact Staff is handling the sales reduction by assuming that the impact of the lost revenue from the lost sales is recovered in the rate design process. Staff notes that the billing determinants have been adjusted downward by the Company.

[7] 2105 TEP Rev Proof CompSenConfid Rebuttal

Q. What is Staff's recommendation on revenue allocation?

A. Based upon the updated CCOSS, the principles discussed above, the impact of the purchase of the Gila River combined cycle plant, the change in allocation methodology and the relative impacts between classes, Staff recommends that the eventual revenue requirements be allocated by increasing the Residential, LGS and Lighting classes 50 percent of the amount to reach parity and increasing all other classes by $23.3 million to obtain the total settlement revenue requirement of $81.5 million.

As shown on page 1 (lines 36 and 38) of Exhibit HS-6, under Staff's recommended revenue allocation the Residential class receives 66.9 percent of the overall $81.5 million settlement increase. The impact on the Residential class will be a 19.8 percent increase in margin, but when combined with changes in the Purchased Power and Fuel Adjustment Clause, the increase will amount to a 10 percent increase overall. Under Staff's proposal, all classes receive an increase.

Q. If Staff's recommended revenue allocation is adopted, what will the class returns be?

A. The results of the proposed revenue allocation are forecasted in Exhibit HS-6 page 1 line 32. The UROR of the "low UROR" classes (Residential, LGS and Lighting) will increase and the UROR of the "high UROR" class will decrease, moving classes towards parity.

Q. Please explain why, if the Residential, LGS and Lighting classes are being subsidized by other classes, Staff is not recommending class revenue increases to bring those classes to parity, which would be consistent with the rate design plan Staff is recommending and which you have detailed above.

A. Staff's plan articulates the concept that "Rates should be based on costs derived from class cost of service studies…", however, the plan is a long-term plan.

Exhibit HS-6 shows that to bring the Residential class to parity would require a class revenue increase of 134 percent of the total settlement increase, an increase of 7.5 of the total settlement increase for the LGS class and an increase of 1.5 percent of the total settlement increase for the Lighting class.

As explained above, revenue allocation is not just an algorithm-based process but is tempered by a Commission's evaluation of other factors. Also Staff's recommendation to move the underperforming classes towards removing the subsidy allows for the completion of the process in following cases.

RATE DESIGN

Q. How were the rate design and associated impacts developed?

A. The Company's models provided in STF 31.14 were used to develop the various rates. The Company's models included the transfer of customers to the new MGS and 138 kV rates with the updated billing determinants. Staff's revenue allocation was different than the Company's therefore the rate design is different. The Company also assumed a $17 residential Basic Service Charge ("BSC"), which is not supported by the latest CCOSS; instead, a $15 residential BSC was used. During rate design the allocation to the 138 kV class was approximately $450,000 less in order to maintain parity with the LPS rates. This amount was recovered in the GS and LGS rates.

Q. What changes does Staff recommend to the proposed residential rate?

A. Staff acknowledges that the Company rebuttal is now recommending the same $17 BSC as Staff proposed in its direct testimony. However, the updated unit cost for the Residential class is now lower at $15.62.[8] The revenue allocated to the Residential class should be

[8] STF 31.11 CCOSS Schedule G-6-1, line 24

collected first by an increase in the BSC up to $15.00, with the remainder (if any) recovered by increased energy charges to begin to levelize the tiers. Applying the revenue increase to the BSC first and eliminating the third and fourth tiers will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

Q. What is the impact on residential customers of Staff's recommendations?

A. Based upon settlement increase in revenue requirements along with Staff's revenue allocation and rate design changes, residential customers would see increases as shown in Exhibit HS-8.

Q. What changes does Staff recommend to the SGS rate?

A. Staff acknowledges that the Company is now recommending a $27 BSC, which is similar to Staff's proposal of $26.80 in its direct testimony. Staff can accept this unless it needs to be reduced to meet the class revenue requirements with the remainder (if any) recovered by increased energy charges. Applying the revenue increase to the BSC first will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

The Company's revised proposal to move a customer to the new MGS rate "if the customer's consumption meets or exceeds 24,000 kWh in consecutive months" is appropriate as it does not penalize a customer for a single usage excursion.

Q. What is the impact on SGS customers of Staff's recommendations?

A. Based upon Staff's recommended overall increase in revenue requirements along with its revenue allocation and rate design changes, GS and SGS customers would see increases as shown in Exhibit HS-8.

Q. The existing residential and SGS rates are not Three-Part-TOU rates and therefore are not in accordance with the Staff's long-term rate design plan. What do you recommend for an initial step?

A. Staff recommends that the Commission approve in this proceeding optional Three-Part-TOU rates for residential and SGS customers. As customers gain experience with these optional rates and see their demand on their monthly bills, the Commission can consider other steps in the Company's next rate case.

The Company has provided its proposed residential and SGS demand rates along with an explanation of how they were developed by Mr. Bachmeier. These rates were developed at the revenue requirement and revenue allocation proposed by the Company in its rebuttal and will need to change when the final class revenues are set to preserve parity with other rate alternatives.

Q. What is the alternative rate proposal for many residential customers sponsored by the Residential Utility Consumer Office ("RUCO")?

A. RUCO is recommending that all customers using 950 kWh or more per month on average over an entire year be transitioned to a three-tier volumetric TOU rate with a summer peak of 3:00 p.m. to 7:00 p.m. (and a winter peak of 6:00 a.m. to 9:00 a.m.). This transition would be done by default but the customers would have the ability to opt-out and return to the inclining block rate plan.[9]

Q. What are Staff's concerns about this proposal?

A. Staff has concerns about a mandatory transition, when and how the average is determined (Test Year usage, rate effective year usage, normalized usage), whether the transition is a

[9] Huber Direct 28:1

continuing review (customers reaching the threshold would be transitioned shortly thereafter) or a one-time event, having differing peak periods from other rates (if that is proposed) and RUCO's reliance on customer inertia (or lack of information) to have a significant portion of customers stay on the rate.

Staff is also concerned that the percentage of customers who would return to their former rate may vary based on the season their transition occurs or even just an abnormally hot month. To avoid gaming, rates are often restricted to a full year of applicability, but that may not be the case here. Also, the customer service impact of a mass volume of opt-out (returning) customers could cause havoc and impair any future implementation of a TOU and/or other rate design. Because of these issues, Staff cannot support RUCO's TOU proposal.

Q. What changes does Staff recommend to the MGS rate?

A. Staff acknowledges the Company's changes to its MGS proposal. We still have concerns about the mandatory transition to the LGS rate at the second excursion above 300 kW (raised from one excursion above 250 kW) because the MGS customer may hit the second 300 kW excursion before it receives the Company's proposed letter, a situation Staff believes can be resolved with the Company.[10]

Staff is also encouraged that the Company has defined a transition plan for customers moving from SGS non-demand rates to MGS demand rates that provides education along with a learning period for those customers.[11] Further, the Company asserts that it has identified "a handful" of accounts that are counter-seasonal (winter focused) and the Company is proposing to address these non-homogeneous customers with a seasonality clause and

[10] Jones Rebuttal 13:3
[11] Jones Rebuttal 14:23

provisions such as waiving the ratchet and cap, but applying Section 7.C.7.g. Subject to a cost of service subclass review in the next case, Staff has greatly reduced concerns about the new MGS rate.

Q. What is the impact on MGS customers of Staff's recommendations?

A. Based upon Staff's recommended overall increase in revenue requirements, along with its revenue allocation and rate design changes, MGS customers would see increases as shown in Exhibit HS-8.

Q. Is there some risk when significant rate design changes are made?

A. Yes. Rate design changes may have unintended results for "outlier" or "non-normal" MGS customers who do not fit neatly into their apparent customer class. The imposition of demand rates and a ratchet (if approved) may also have unforeseen impacts.

Staff has reviewed the Company's criteria for this issue[12] and suggests, as provided for in the previous TEP settlement (Docket No. E-01933A-12-0291), the Commission should keep the rate design portion of this rate case open for at least 18 months after the completion of the transition to MGS rates to account for unanticipated customer rate impacts that are determined to be inconsistent with the public interest. Items 2 and 3 of the Company's proposal are reasonable.

Q. What changes does Staff recommend to the LGS rate?

A. Staff acknowledges the Company's changes to its LGS proposal.[13] Staff can accept the common BSC of $950 for all LGS customers. The revenue allocated to the LGS rate should be collected first by an increase in the demand charge, with the remainder (if any) recovered

[12] Jones Rebuttal 10:12
[13] 17:17 and 19:1

by increased energy charges. Applying the revenue increase to the demand charge first and then to energy charges will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

Q. What is the impact on LGS customers of Staff's recommendations?

A. Based upon Staff's recommended overall increase in revenue requirements along with its revenue allocation and rate design changes, LGS customers would see increases as shown in Exhibit HS-8.

Q. What changes does Staff recommend to the LPS rate?

A. Staff acknowledges the Company's changes to its LPS proposal.[14] The proposed BSC of $10,000 is offset by a reduced demand charge. The revenue allocated to the LPS rate should be collected first by an increase in the BSC, with the remainder (if any) recovered by increased demand and then energy charges. Applying the revenue increase to the BSC first and then to demand charges will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

Q. What is the impact on LPS customers of Staff's recommendations?

A. Based upon Staff's recommended overall increase in revenue requirements along with its revenue allocation and rate design changes, LPS customers would see increases as shown in Exhibit HS-8.

Q. Is the Company's proposal for a new 138 kV rate appropriate?

A. Staff acknowledges the Company's changes to its 138 kV proposal.[15] The proposed BSC of $15,000 is offset by a reduced demand charge. The revenue allocated to the rate should be

[14] Jones Direct 19:10
[15] Jones Direct 19:10

collected first by an increase in the BSC, with the remainder (if any) recovered by increased demand and then energy charges. Applying the revenue increase to the BSC first and then to demand charges will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

Q. What changes does Staff recommend to the Lighting Service rate?

A. Consistent with Staff's revenue allocation for the Residential and LGS classes, Staff is proposing an increase for the Lighting class.

Q. What is the impact on Lighting Service customers of Staff's recommendations?

A. Based upon Staff's recommended overall increase in revenue requirements along with its revenue allocation and rate design changes, Lighting Service customers would see increases as shown in Exhibit HS-8.

Lifeline

Q. Please describe the Company's updated proposal for Lifeline customers?

A. The Company proposes to move Lifeline customers to their choice of an existing residential rate but with a fixed Lifeline discount. Under this concept, Lifeline customers can easily determine their discount and the impact on their bills if their financial situation were to improve. The Company proposes to adjust the discount provided to Lifeline customers to mitigate the impact of this change and the rate increase to amounts similar to non-Lifeline customers for the majority of customers.[16]

[16] Jones Rebuttal 21:22

Q. What is the value/cost of the Lifeline discounts?

A. The Company estimates the discounts totaled $1,798,110 during the Test Year for nearly 15,000 Lifeline customers and now will total approximately $2.8 million.[17]

Q. Does Staff support the Lifeline proposal?

A. In keeping with Staff's long-term plan for rate design, Staff supports the Company's Lifeline proposal subject to a few concerns.

- The impact on Lifeline customers of any rate change is dependent on the level of residential rate change and the structure of the residential rates. Staff recommends that the validation of the Lifeline impact and the required discounts be performed after the revenue allocation and residential rate design is determined.
- The Company should "prove out" that the level of Lifeline discounts after the finalized changes in rates is at or above the Test Year value.
- The Company should address those Lifeline customers who will see a significant increase in their bill as a result of adopting the fixed discount. Some customers have such a deep discount that even a $40 monthly Lifeline credit may not keep them from seeing a significant increase. In these cases, the Company should confirm that the rate is frozen, that the customer is eligible for this large discount and that there is not another Lifeline rate that would be more advantageous.
    - While I have retained the rate design for those Lifeline customers so the parties can see the impact, Staff suggests that the Company provide suggestions to minimize the impact either by providing a larger discount or by holding those customers in their frozen rate structure.

[17] Jones Rebuttal 22:4

Buy-Through

Q. Please describe the Experimental Rider 14 "Buy-Through" proposal submitted by the Company.

A. The Company was required to introduce the "Buy-Through" as a result of a settlement during the merger process,[18] but the Company does not support this tariff change.[19] The Buy-Through would allow a select subset of larger customers to obtain their energy supply outside of the Company's power supply mechanism that at present serves all customers.

Q. What is Staff's position on the "Buy-Through"?

A. Because the Company is not supporting this concept, there is no record describing the benefits (or costs) to non-participating customers. Staff does not object to a "Buy-Through" mechanism, if there are no adverse impacts and no costs to all other customers. Staff is concerned that Buy-Through customers may return when the market becomes tight (expensive) and thus impact customers who did not or could previously take advantage of the Buy-Through provisions. Staff opposes recouping any allegedly lost Buy-Through revenue and likewise opposes any deferral of allegedly lost Buy-Through revenue. This opposition to recouping lost incremental revenues extends to the use of the LFCR for that purpose.[20]

Q. Can you explain the potential impact of the "Buy-Through" on those customers left behind?

A. Under the concept described by the Company and supported by some parties in this case there could be a detrimental effect on those customers that cannot or will not use the Buy-Through mechanism. These customers would be those too small to be cost efficiently managed due to the additional billing needed to account for the mechanism and would

[18] Jones Direct 61:18
[19] Jones Direct 61:23
[20] Jones Direct 80:4

include all residential, SGS and proposed MGS customers. An additional group would be larger customers who may choose not to use the Buy-Through, even if they do qualify based on size due to internal costs (to manage energy purchases) or inexperience in an unregulated market. These customers may experience uneven competition that results from (large) customers, with a subset given (or even chosen by lottery) a lower energy price than other similar customers. In essence, a Buy-Through may help choose winners and losers within the business community.

Q. Please explain how "Buy-Through" impacts left behind customers based on algebra.

A. The Company's power supply consists of two parts, assets owned by the Company and power purchased from the market. The cost to customers (subject to impacts such as voltage) is (A+P)/S = R ($/MWh), where A equals the costs of power derived from the Company's assets and P equals the costs of energy purchased on the market. The relative cost of power can depend on the differing fuel mix of the Company versus the market, the age of the Company's assets, the costs of the Company's assets and how desperate or aggressive the power sellers are in the marketplace at any given time.

Since a number of parties in this case are clamoring for the opportunity to purchase on the market (absent some customer's specific load pattern), those parties must be convinced that energy presently available on the open market is lower in cost than the value R. This would imply that at present (for equal volumes) P is less than A. If as a result of the Buy-Through some sales are no longer covered by lower cost P energy, then the new value of R will increase to R+. The change in R will be determined by how much the volume of purchased power drops and the relative difference in cost between A and P. Since the new price (R+) is paid only by those customers that remain, the costs of captive customers will increase.

At some point in the future as the power market becomes tighter, P (purchased power) may become more costly than A. At that point the Buy-Through customers may return to the Company's power supply in order to seek lower cost power. At that point the Company will have to increase its purchases of the increased cost P energy (or build or buy new assets at higher cost) in order to serve the returning customers creating a new cost R++, which by average cost regulation would apply to all customers and adversely impact the non Buy-Through customers a second time.

In essence, this is a heads we win, and a tails you lose scenario.

Q. What is Freeport/AECC/Noble's ("FAN") position on the "Buy-Through"?

A. FAN recommends a longer period of time for the program (until the next rate effective date and no less than four years)[21], increases the proposed cap from 30 to 60 MW[22], allowing sites with loads as low as 200 kW to participate along with a minimum load of 3 MW compared to APS's 10 MW[23], broadening the rates eligible[24], a lower management fee[25] and the use of approximately $7.5 million of reduction of the revenue requirement to subsidize the Buy-Through costs if needed[26].

Q. What are the effects of FAN's position on the "Buy-Through" on other remaining customers?

A. FAN's proposals will increase the number of customers that could use the Buy-Through, potentially raise billing costs; raise the amount of lower cost purchased power removed from the algebraic equation; and "spending" the non-existent $7.5 million reduction.

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[21] Higgins Direct 33:12
[22] Higgins Direct 33:21
[23] Higgins Direct 34:3
[24] Higgins Direct 34:12
[25] Higgins Direct 35:15
[26] Higgins Direct 38:3

When a utility makes its revenue requirements request it has the burden to prove those rates are just and reasonable. The Commission's final decision determines the just and reasonable level of revenue for the utility. The amount between those two values is not a saving to be given to one or more classes but by definition never existed (non-existent). If instead FAN were implying that the $7.5 million figure "would not be applied to a change in rates per se,"[27] then Staff is concerned that left behind customers in the "LGS, LPS and High Voltage..." classes would be paying for their competitors' privilege to temporarily leave the system and some of its fixed costs to the remaining customers.

If the concept proposed by FAN does not result in full utilization, then FAN proposes a new mechanism to recapture all or a portion of the $7.5 million for the remaining larger customers, at whose administrative cost?

Q. What is Kroger's position on the "Buy-Through"?

A. Kroger appears to recommend that LGS, LPS-TOU and 138 kV customers would be eligible for the Buy-Through and allow accounts with loads as low as 100 kW to participate,[28] argues for a lower management fee[29] and increases the proposed cap from 30 to 65 MW.[30]

Q. What are the effects of Kroger's position on the "Buy-Through" on other remaining customers?

A. Kroger's proposals will increase the number of customers that could use the Buy-Through, potentially raise billing costs and raise the amount of lower cost purchased power removed from the algebraic equation.

[27] Higgins Direct 38:12
[28] Baron Direct 25:13
[29] Baron Direct 26:21
[30] Baron Direct 27:5

Q. What is Wal-Mart's position on the "Buy-Through"?

A. Wal-Mart recommends an (actual) cost-based management fee[31], a minimum participation size of 1,000 kW[32], aggregation of "utility accounts within its corporate family" (although the definition for other potential Buy-Through customers is not provided).[33] All commercial and industrial could participate regardless of rate class[34], raising the cap to 250 MW (lower end of purchased power) and no time limit[35]. Wal-Mart argues that its proposal would shift the risk of wholesale market purchases from the remaining customers.[36]

Q. What are the effects of Wal-Mart's position on the "Buy-Through" on other remaining customers?

A. Wal-Mart's proposals may increase the number of customers who could use the Buy-Through, potentially raise billing costs; raise the amount of lower cost purchased power removed from the algebraic equation; and if considered for adoption raises several questions. Its definition for aggregation "utility accounts within its corporate family" is open to interpretation. For example, would that include franchises owned by individual corporations, but operating under a corporate name, processes, supply chain and other factors? Allowing all commercial and industrial customers to participate raises questions as to why governmental bodies and even aggregates of residential customers are not included. Increasing the cap to effectively all of the Company's purchased power raises the algebraic question and also how periods of no purchases (low loads) would be handled, e.g., would negative load costs be charged to Buy-Through customers or saddle the remaining customers if flexibility is lost?

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[31] Hendrix Direct 5:15
[32] Hendrix Direct 6:3
[33] Hendrix Direct 6:9
[34] Hendrix Direct 6:14
[35] Hendrix Direct 8:5
[36] Hendrix Direct 9:6

Q. What is Wal-Mart's "Rate Support Rider"?

A. Wal-Mart is suggesting removing the subsidy for residential customers (it calculates at $83 million) over a period of eight years by closing the gap at 12.5 percent each year until the subsidy is eliminated. Its proposal is planned to be revenue neutral.

Q. Should there be some concerns if the Commission approves a "Rate Support Rider"?

A. Yes. The planned Rate Support Rider would lock-in a course of rate increases for residential customers over the next eight years, regardless of any intervening economic conditions. It would also presume that the relative positions of the customer classes (the subsidy) will not change over that period due to increased DG penetration, EE or opening or closing of new accounts (residential, commercial, industrial and governmental). Since the sales over the next eight years will be different from the Test Year, an adjustment and reconciliation methodology and Plan of Administration must be developed at the implementation of the Rate Support Rider. These items highlight that the Commission should not move forward on this concept without a detailed debate and understanding of its effects and supposed benefits.

LOST FIXED COST RECOVERY

Q. Has the Company raised its concerns about the LFCR mechanism?

A. Yes. Company witness Hutchens argues for full recovery of "...non-fuel costs that otherwise go unrecovered due to Commission-mandated DG and EE programs. There is no reasonable basis for excluding generation costs from the LFCR as they constitute a large portion of the fixed costs incurred to meet retail customer demand."[37]

Company witness Jones argues, "When rates are created, the fixed costs associated with Company-owned generation facilities and related equipment are included in the costs

[37] Hutchens Rebuttal 18:17

allocated to the various rate classes. Those costs are then spread over an approved number of billing determinants, either demand or volumetric, depending on the class. Once in the rates, the Company must realize that level of billing determinants in all future years (until rates are reset in a future rate case) to fully recover its fixed costs."[38]

Q. Did your direct testimony highlight the impact of the Company's proposal to add to the items included in the LFCR?

A. Yes. I cited Company witness Jones' testimony that indicated the impact would be approximately $13 million, an additional 1.7 percent.[39]

Q. Did your direct testimony highlight that generation is fungible?

A. Yes. I highlighted that energy could be delivered to a new customer, an existing customer using slightly more energy, an economic development customer or sold off-system.[40]

I also highlighted that the Company is forecasting increasing requirements in net demand, increasing numbers of customers, increasing reference case sales, and increasing firm wholesale sales.[41] The Company is requesting an Economic Development Rider that would increase sales.

Q. How is generation different from distribution?

A. Generation is located much further from the end use customer and can be connected to any, or all, potential customers through the transmission system. Distribution equipment is more closely connected to a customer, or a smaller group of customers. For example a pole or pad mounted distribution transformer serves only the connected customer(s). Thus, distribution

[38] Jones Rebuttal 25:5
[39] Solganick Direct 52:10
[40] Solganick Direct 54:1
[41] Solganick Direct 54:8

asset costs can go unrecovered while generation can be refocused on new customers or increased sales. This difference in diversity and ability to refocus is why the LFCR does not and should not include generation costs.

Q. Why should the LFCR mechanism not be changed to recover generation and other demand costs?

A. Based on the Company's forecasts, generation and other fixed costs that are not recovered through the LFCR mechanism may be paid for by the new sales and/or new customers. The LFCR is not designed to mitigate the Company's risks from level or declining sales due to factors other than EE and DG.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

		TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE	[redacted]	LIGHTING
		(A)	(B)	(C)	(E)		(H)
	Equal %						
1	Rate of Return on Rate Base	7.19%	1.08%	20.72%	9.35%		2.75%
2	UROR	1.000	0.151	2.880	1.299		0.383
3							
4	Proposed Sales Revenue	$976,113,911	$435,549,582	$269,264,513	$128,037,206		$5,033,161
5							
6	Change in Margin Revenue	$81,500,000	$36,365,931	$22,482,066	$10,690,384		$420,241
7	% Change in Margin Revenue	13.5%	13.2%	12.2%	15.6%		12.7%
8	% of the Class Change in Margin Revenue	100.0%	44.6%	27.6%	13.1%		0.5%
9							
10							
11	Change in Total Revenue	$48,973,644	$23,936,821	$6,119,683	$16,559,193		$275,343
12	% Change in Total Revenue	5.3%	5.8%	2.3%	14.9%		5.8%
13	% Class Change of Total Revenue	100.0%	48.9%	12.5%	33.8%		0.6%
14							
15	**All UROR = 1.000**						
16	Rate of Return on Rate Base	7.19%	7.19%	7.19%	7.19%		7.19%
17	UROR	1.000	1.000	1.000	1.000		1.000
18							
19	Proposed Sales Revenue	$976,113,911	$508,185,751	$209,968,547	$123,487,762		$5,795,856
20							
21	Change in Margin Revenue	$81,500,000	$109,002,100	($36,813,900)	$8,140,940		$1,182,935
22	% Change in Margin Revenue	13.5%	39.5%	-20.0%	9.0%		35.9%
23	% of the Class Change in Margin Revenue	100.0%	133.7%	-45.2%	7.5%		1.5%
24							
25							
26	Change in Total Revenue	$48,973,644	$96,572,990	($53,176,284)	$12,009,749		$1,038,038
27	% Change in Total Revenue	5.3%	23.5%	-20.2%	10.8%		21.8%
28	% Class Change of Total Revenue	100.0%	197.2%	-108.6%	24.5%		2.1%
29							
30	**50% to UROR = 1.000**						
31	Rate of Return on Rate Base	7.19%	2.61%	19.11%	5.74%		3.75%
32	UROR	1.000	0.363	2.656	0.798		0.521
33							
34	Proposed Sales Revenue	$976,113,911	$453,684,701	$262,203,115	$120,417,292		$5,204,388
35							
36	Change in Margin Revenue	$81,500,000	$54,501,050	$15,420,669	$3,070,470		$591,468
37	% Change in Margin Revenue	13.5%	19.8%	8.4%	4.5%		17.9%
38	% of the Class Change in Margin Revenue	100.0%	66.9%	18.9%	3.8%		0.7%
39							
40							
41	Change in Total Revenue	$48,973,644	$42,071,940	($941,715)	$8,939,279		$446,570
42	% Change in Total Revenue	5.3%	10.2%	-0.4%	8.0%		9.4%
43	% Class Change of Total Revenue	100.0%	85.9%	-1.9%	18.3%		0.9%
44							
45							

		TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE	[redacted]	LIGHTING
		(A)	(B)	(C)	(E)		(H)
	70% to UROR = 1.000						
1	Rate of Return on Rate Base	7.19%	4.44%	15.60%	6.32%		5.13%
2	UROR	1.000	0.618	2.169	0.879		0.713
3							
4	Proposed Sales Revenue	$976,113,911	$475,485,121	$246,829,903	$121,645,480		$5,440,975
5							
6	Change in Margin Revenue	$81,500,000	$76,301,470	$47,456	$4,298,658		$828,055
7	% Change in Margin Revenue	13.5%	27.7%	0.0%	6.3%		25.1%
8	% of the Class Change in Margin Revenue	100.0%	93.6%	0.1%	5.3%		1.0%
9							
10							
11	Change in Total Revenue	$48,973,644	$63,872,360	($16,314,928)	$10,167,467		$683,157
12	% Change in Total Revenue	5.3%	15.5%	-6.2%	9.1%		14.4%
13	% Class Change of Total Revenue	100.0%	130.4%	-33.3%	20.8%		1.4%
14							
15	**65% to UROR = 1.000**						
16	Rate of Return on Rate Base	7.19%	3.98%	16.48%	6.18%		4.78%
17	UROR	1.000	0.554	2.291	0.859		0.665
18							
19	Proposed Sales Revenue	$976,113,911	$470,035,016	$250,673,206	$121,338,433		$5,381,828
20							
21	Change in Margin Revenue	$81,500,000	$70,851,365	$3,890,759	$3,991,611		$768,908
22	% Change in Margin Revenue	13.5%	25.7%	2.1%	5.8%		23.3%
23	% of the Class Change in Margin Revenue	100.0%	86.9%	4.8%	4.9%		0.9%
24							
25							
26	Change in Total Revenue	$48,973,644	$58,422,255	($12,471,625)	$9,860,420		$624,011
27	% Change in Total Revenue	5.3%	14.2%	-4.7%	8.8%		13.1%
28	% Class Change of Total Revenue	100.0%	119.3%	-25.5%	20.1%		1.3%
29							
30	**60% to UROR = 1.000**						
31	Rate of Return on Rate Base	7.19%	3.53%	17.36%	6.03%		4.44%
32	UROR	1.000	0.490	2.413	0.838		0.617
33							
34	Proposed Sales Revenue	$976,113,911	$464,584,911	$254,516,509	$121,031,386		$5,322,682
35							
36	Change in Margin Revenue	$81,500,000	$65,401,260	$7,734,062	$3,684,564		$709,761
37	% Change in Margin Revenue	13.5%	23.7%	4.2%	5.4%		21.5%
38	% of the Class Change in Margin Revenue	100.0%	80.2%	9.5%	4.5%		0.9%
39							
40							
41	Change in Total Revenue	$48,973,644	$52,972,150	($8,628,322)	$9,553,373		$564,864
42	% Change in Total Revenue	5.3%	12.9%	-3.3%	8.6%		11.9%
43	% Class Change of Total Revenue	100.0%	108.2%	-17.6%	19.5%		1.2%
44							
45							

		TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE	[redacted]	LIGHTING
		(A)	(B)	(C)	(E)		(H)
	55% to UROR = 1.000						
1	Rate of Return on Rate Base	7.19%	3.07%	18.23%	5.89%		4.10%
2	UROR	1.000	0.426	2.535	0.818		0.569
3							
4	Proposed Sales Revenue	$976,113,911	$459,134,806	$258,359,812	$120,724,339		$5,263,535
5							
6	Change in Margin Revenue	$81,500,000	$59,951,155	$11,577,365	$3,377,517		$650,614
7	% Change in Margin Revenue	13.5%	21.7%	6.3%	4.9%		19.7%
8	% of the Class Change in Margin Revenue	100.0%	73.6%	14.2%	4.1%		0.8%
9							
10							
11	Change in Total Revenue	$48,973,644	$47,522,045	($4,785,018)	$9,246,326		$505,717
12	% Change in Total Revenue	5.3%	11.5%	-1.8%	8.3%		10.6%
13	% Class Change of Total Revenue	100.0%	97.0%	-9.8%	18.9%		1.0%
14							
15	**45% to UROR = 1.000**						
16	Rate of Return on Rate Base	7.19%	2.15%	19.99%	5.60%		3.41%
17	UROR	1.000	0.299	2.778	0.778		0.474
18							
19	Proposed Sales Revenue	$976,113,911	$448,234,596	$266,048,419	$120,110,245		$5,145,241
20							
21	Change in Margin Revenue	$81,500,000	$49,050,945	$19,263,972	$2,763,423		$532,321
22	% Change in Margin Revenue	13.5%	17.8%	10.4%	4.0%		16.1%
23	% of the Class Change in Margin Revenue	100.0%	60.2%	23.6%	3.4%		0.7%
24							
25							
26	Change in Total Revenue	$48,973,644	$36,621,835	$2,901,588	$8,632,232		$387,424
27	% Change in Total Revenue	5.3%	8.9%	1.1%	7.7%		8.1%
28	% Class Change of Total Revenue	100.0%	74.8%	5.9%	17.6%		0.8%
29							
30	**40% to UROR = 1.000**						
31	Rate of Return on Rate Base	7.19%	1.69%	20.86%	5.45%		3.06%
32	UROR	1.000	0.235	2.900	0.758		0.426
33							
34	Proposed Sales Revenue	$976,113,911	$442,784,491	$269,889,722	$119,803,198		$5,086,095
35							
36	Change in Margin Revenue	$81,500,000	$43,600,840	$23,107,275	$2,456,376		$473,174
37	% Change in Margin Revenue	13.5%	15.8%	12.5%	3.6%		14.3%
38	% of the Class Change in Margin Revenue	100.0%	53.5%	28.4%	3.0%		0.6%
39							
40							
41	Change in Total Revenue	$48,973,644	$31,171,730	$6,744,891	$8,325,185		$328,277
42	% Change in Total Revenue	5.3%	7.6%	2.6%	7.5%		6.9%
43	% Class Change of Total Revenue	100.0%	63.7%	13.8%	17.0%		0.7%
44							
45							

		TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE	[redacted]	LIGHTING
		(A)	(B)	(C)	(E)		(H)
	35% to UROR = 1.000						
1	Rate of Return on Rate Base	7.19%	1.23%	21.74%	5.31%		2.72%
2	UROR	1.000	0.172	3.022	0.738		0.378
3							
4	Proposed Sales Revenue	$976,113,911	$437,334,386	$273,733,025	$119,496,151		$5,026,948
5							
6	Change in Margin Revenue	$81,500,000	$38,150,735	$26,950,578	$2,149,329		$414,027
7	% Change in Margin Revenue	13.5%	13.8%	14.6%	3.1%		12.6%
8	% of the Class Change in Margin Revenue	100.0%	46.8%	33.1%	2.6%		0.5%
9							
10							
11	Change in Total Revenue	$48,973,644	$25,721,625	$10,588,194	$8,018,138		$269,130
12	% Change in Total Revenue	5.3%	6.2%	4.0%	7.2%		5.7%
13	% Class Change of Total Revenue	100.0%	52.5%	21.6%	16.4%		0.5%
14							
15	**30% to UROR = 1.000**						
16	Rate of Return on Rate Base	7.19%	0.78%	22.62%	5.16%		2.37%
17	UROR	1.000	0.108	3.144	0.717		0.330
18							
19	Proposed Sales Revenue	$976,113,911	$431,884,281	$277,576,328	$119,189,104		$4,967,801
20							
21	Change in Margin Revenue	$81,500,000	$32,700,630	$30,793,881	$1,842,282		$354,881
22	% Change in Margin Revenue	13.5%	11.9%	16.7%	2.7%		10.8%
23	% of the Class Change in Margin Revenue	100.0%	40.1%	37.8%	2.3%		0.4%
24							
25							
26	Change in Total Revenue	$48,973,644	$20,271,520	$14,431,498	$7,711,091		$209,983
27	% Change in Total Revenue	5.3%	4.9%	5.5%	6.9%		4.4%
28	% Class Change of Total Revenue	100.0%	41.4%	29.5%	15.7%		0.4%
29							
30	**TEP G-2 STF 31.11**						
31	Rate of Return on Rate Base	7.90%	2.90%	16.27%	19.60%		7.92%
32	UROR	1.000	0.367	2.060	2.481		1.002
33							
34	Proposed Sales Revenue	$999,203,915	$462,043,268	$251,565,091	$150,585,212		$5,991,010
35							
36	Change in Margin Revenue	$104,590,005	$62,859,617	$4,782,644	$33,238,390		$1,378,089
37	% Change in Margin Revenue	17.3%	22.8%	2.6%	48.6%		41.8%
38	% of the Class Change in Margin Revenue	100.0%	60.1%	4.6%	31.8%		1.3%
39							
40							
41	Change in Total Revenue	$72,063,649	$50,430,507	($11,579,739)	$39,107,199		$1,233,192
42	% Change in Total Revenue	7.8%	12.3%	-4.4%	35.1%		25.9%
43	% Class Change in Total Revenue	100.0%	70.0%	-16.1%	54.3%		1.7%
44							
45							

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-R-01	**Residential Service**				
	Basic Service Charge Single Phase Per Mo.	$10.00	$15.00	$5.00	50%
	Basic Service Charge Three Phase Per Mo.	$15.00	$20.00	$5.00	33%
	Sum First 500 kWh	$0.056200	$0.064008	$0.007808	14%
	Sum 501-1,000 kWh	$0.067200	$0.080588	$0.013388	20%
	Sum 1,001-3,500 kWh	$0.079800	$0.080588	$0.000788	1%
	Sum>3,500 kWh	$0.088200	$0.080588	-$0.007612	-9%
	Win First 500 kWh	$0.056200	$0.064008	$0.007808	14%
	Win 501-1,000 kWh	$0.065200	$0.080588	$0.015388	24%
	Win 1,001-3,500 kWh	$0.078100	$0.080588	$0.002488	3%
	Win>3,500 kWh	$0.087100	$0.080588	-$0.006512	-7%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
Solar Block Rate for Residential Electric Service Rate R-01		$0.053463	$0.054412	$0.000949	2%
TE-RXXX	**Residential Service Demand**				
	Basic Service Charge Per Month	N/M	$15.00	N/M	N/M
	Demand 0-7 kW	N/M	$7.40	N/M	N/M
	Demand > 7 kW	N/M	$11.90	N/M	N/M
	Sum kWh	N/M	$0.026659	N/M	N/M
	Win kWh	N/M	$0.026659	N/M	N/M
	Base Power Summer kWh	N/M	$0.035868	N/M	N/M
	Base Power Winter kWh	N/M	$0.032537	N/M	N/M
	PPFAC Charge kWh	N/M	$0.000000	N/M	N/M
TE-201A	**Special Residential Electric Service**				
	Basic Service Charge	$10.00	$15.00	$5.00	50%
	Sum First 500 kWh	$0.050600	$0.064008	$0.013408	26%
	Sum 501-1,000 kWh	$0.060500	$0.080588	$0.020088	33%
	Sum 1,001-3,500 kWh	$0.071800	$0.080588	$0.008788	12%
	Sum>3,500 kWh	$0.079400	$0.080588	$0.001188	1.5%
	Win First 500 kWh	$0.050600	$0.064008	$0.013408	26%
	Win 501-1,000 kWh	$0.058700	$0.080588	$0.021888	37%
	Win 1,001-3,500 kWh	$0.070300	$0.080588	$0.010288	15%
	Win>3,500 kWh	$0.078400	$0.080588	$0.002188	3%
	Base Power Summer kWh	$0.035111	$0.028694	-$0.006417	-18%
	Base Power Winter kWh	$0.031532	$0.026030	-$0.005502	-17%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-201B	**Special Residential Electric Service Time of Use**				
	Basic Service Charge	$11.50	$15.00	$3.50	30%
	Sum On-peak First 500 kWh	$0.056800	$0.064008	$0.007208	13%
	Sum On-peak 501-1,000 kWh	$0.056800	$0.080588	$0.023788	42%
	Sum On-peak1,001-3,500 kWh	$0.056800	$0.080588	$0.023788	42%
	Sum On-peak >3,500 kWh	$0.056800	$0.080588	$0.023788	42%
	Sum Off-peak First 500 kWh	$0.044000	$0.064008	$0.020008	45%
	Sum Off-peak 501-1,000 kWh	$0.044000	$0.080588	$0.036588	83%
	Sum Off-peak1,001-3,500 kWh	$0.044000	$0.080588	$0.036588	83%
	Sum Off-peak >3,500 kWh	$0.044000	$0.080588	$0.036588	83%
	Win On-peak First 500 kWh	$0.048300	$0.064008	$0.015708	33%
	Win On-peak 501-1,000 kWh	$0.048300	$0.080588	$0.032288	67%
	Win On-peak1,001-3,500 kWh	$0.048300	$0.080588	$0.032288	67%
	Win On-peak >3,500 kWh	$0.048300	$0.080588	$0.032288	67%
	Win Off-peak First 500 kWh	$0.035500	$0.064008	$0.028508	80%
	Win Off-peak 501-1,000 kWh	$0.035500	$0.080588	$0.045088	127%
	Win Off-peak1,001-3,500 kWh	$0.035500	$0.080588	$0.045088	127%
	Win Off-peak >3,500 kWh	$0.035500	$0.080588	$0.045088	127%
	Base Power Summer On-Peak kWh	$0.050669	$0.041328	-$0.009341	-18%
	Base Power Summer Off-Peak kWh	$0.026679	$0.021400	-$0.005279	-20%
	Base Power Winter On-peak kWh	$0.032893	$0.027114	-$0.005779	-18%
	Base Power Winter Off-peak kWh	$0.027092	$0.022474	-$0.004618	-17%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-R80	**Residential Time of Use**				
	Basic Service Charge	$11.50	$15.00	$3.50	30%
	Sum On-peak First 500 kWh	$0.066800	$0.064008	-$0.002792	-4%
	Sum On-peak 501-1,000 kWh	$0.066800	$0.080588	$0.013788	21%
	Sum On-peak1,001-3,500 kWh	$0.066800	$0.080588	$0.013788	21%
	Sum On-peak >3,500 kWh	$0.066800	$0.080588	$0.013788	21%
	Sum Off-peak First 500 kWh	$0.051800	$0.064008	$0.012208	24%
	Sum Off-peak 501-1,000 kWh	$0.051800	$0.080588	$0.028788	56%
	Sum Off-peak1,001-3,500 kWh	$0.051800	$0.080588	$0.028788	56%
	Sum Off-peak >3,500 kWh	$0.051800	$0.080588	$0.028788	56%
	Win On-peak First 500 kWh	$0.056800	$0.064008	$0.007208	13%
	Win On-peak 501-1,000 kWh	$0.056800	$0.080588	$0.023788	42%
	Win On-peak1,001-3,500 kWh	$0.056800	$0.080588	$0.023788	42%
	Win On-peak >3,500 kWh	$0.056800	$0.080588	$0.023788	42%
	Win Off-peak First 500 kWh	$0.041800	$0.064008	$0.022208	53%
	Win Off-peak 501-1,000 kWh	$0.041800	$0.080588	$0.038788	93%
	Win Off-peak1,001-3,500 kWh	$0.041800	$0.080588	$0.038788	93%
	Win Off-peak >3,500 kWh	$0.041800	$0.080588	$0.038788	93%
	Base Power Summer On-Peak kWh	$0.050669	$0.051660	$0.000991	2%
	Base Power Summer Off-Peak kWh	$0.026679	$0.026750	$0.000071	0%
	Base Power Winter On-peak kWh	$0.032893	$0.033893	$0.001000	3%
	Base Power Winter Off-peak kWh	$0.027092	$0.028092	$0.001000	4%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-RXXX	**Residential Demand Time of Use**				
	Basic Service Charge Per Month	N/M	$15.00	N/M	N/M
	Demand 0-7 kW	N/M	$7.40	N/M	N/M
	Demand > 7 kW	N/M	$11.90	N/M	N/M
	Sum On-peak kWh	N/M	$0.026659	N/M	N/M
	Sum Off-peak kWh	N/M	$0.026659	N/M	N/M
	Win On-peak kWh	N/M	$0.026659	N/M	N/M
	Win Off-peak kWh	N/M	$0.026659	N/M	N/M
	Base Power Summer On-Peak kWh	N/M	$0.051660	N/M	N/M
	Base Power Summer Off-Peak kWh	N/M	$0.026750	N/M	N/M
	Base Power Winter On-peak kWh	N/M	$0.033893	N/M	N/M
	Base Power Winter Off-peak kWh	N/M	$0.028092	N/M	N/M
	PPFAC Charge kWh	N/M	$0.000000	N/M	N/M
TE-R8	**Residential Time of Use Super Peak**				
	Basic Service Charge	$11.50	$15.00	$3.50	30%
	Sum On-peak First 500 kWh	$0.097100	$0.064008	-$0.033092	-34%
	Sum On-peak 501-1,000 kWh	$0.097100	$0.080588	-$0.016512	-17%
	Sum On-peak1,001-3,500 kWh	$0.120100	$0.080588	-$0.039512	-33%
	Sum On-peak >3,500 kWh	$0.120100	$0.080588	-$0.039512	-33%
	Sum Off-peak First 500 kWh	$0.048500	$0.064008	$0.015508	32%
	Sum Off-peak 501-1,000 kWh	$0.048500	$0.080588	$0.032088	66%
	Sum Off-peak1,001-3,500 kWh	$0.071500	$0.080588	$0.009088	13%
	Sum Off-peak >3,500 kWh	$0.071500	$0.080588	$0.009088	13%
	Win On-peak First 500 kWh	$0.089100	$0.064008	-$0.025092	-28%
	Win On-peak 501-1,000 kWh	$0.089100	$0.080588	-$0.008512	-10%
	Win On-peak1,001-3,500 kWh	$0.112100	$0.080588	-$0.031512	-28%
	Win On-peak >3,500 kWh	$0.112100	$0.080588	-$0.031512	-28%
	Win Off-peak First 500 kWh	$0.038500	$0.064008	$0.025508	66%
	Win Off-peak 501-1,000 kWh	$0.038500	$0.080588	$0.042088	109%
	Win Off-peak1,001-3,500 kWh	$0.061500	$0.080588	$0.019088	31%
	Win Off-peak >3,500 kWh	$0.061500	$0.080588	$0.019088	31%
	Base Power Summer On-Peak kWh	$0.080100	$0.081060	$0.000960	1%
	Base Power Summer Off-Peak kWh	$0.022200	$0.022750	$0.000550	2%
	Base Power Winter On-peak kWh	$0.040200	$0.041293	$0.001093	3%
	Base Power Winter Off-peak kWh	$0.020500	$0.021492	$0.000992	5%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-R01BC	**Residential Service R-01 Bright Community Solar**				
	Basic Service Charge Single Phase	$10.00	$15.00	$5.00	50%
	Sum First 500 kWh	$0.056200	$0.064008	$0.007808	14%
	Sum 501-1,000 kWh	$0.067200	$0.080588	$0.013388	20%
	Sum 1,001-3,500 kWh	$0.079800	$0.080588	$0.000788	1%
	Sum>3,500 kWh	$0.088200	$0.080588	-$0.007612	-9%
	Win First 500 kWh	$0.056200	$0.064008	$0.007808	14%
	Win 501-1,000 kWh	$0.065200	$0.080588	$0.015388	24%
	Win 1,001-3,500 kWh	$0.078100	$0.080588	$0.002488	3%
	Win>3,500 kWh	$0.087100	$0.080588	-$0.006512	-7%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE4-01	**Lifeline Residential Service Standard (Frozen 1996 - R-04-01F Senior % Discount)**				
	Basic Service Charge Per Month	$6.90	$15.00	$8.10	117%
	Sum First 500 kWh	$0.061100	$0.064008	$0.002908	5%
	Sum 501-1,000 kWh	$0.061100	$0.080588	$0.019488	32%
	Sum >1,000 kWh	$0.061100	$0.080588	$0.019488	32%
	Win First 500 kWh	$0.057000	$0.064008	$0.007008	12%
	Win 501-1,000 kWh	$0.057000	$0.080588	$0.023588	41%
	Win >1,000 kWh	$0.057000	$0.080588	$0.023588	41%
	Base Power Summer kWh	$0.033198	$0.035868	$0.002670	8%
	Base Power Winter kWh	$0.025698	$0.032537	$0.006839	27%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE4-21	**Lifeline Residential Time of Use (Frozen 1996 - Senior % Discount)**				
	Basic Service Charge Per Month	$8.86	$15.00	$6.14	69%
	Sum On-Peak First 500 kWh	$0.078800	$0.064008	-$0.014792	-19%
	Sum On-Peak 501-1,000 kWh	$0.078800	$0.080588	$0.001788	2%
	Sum On-Peak >1,000 kWh	$0.078800	$0.080588	$0.001788	2%
	Sum Off-Peak First 500 kWh	$0.030100	$0.064008	$0.033908	113%
	Sum Off-Peak 501-1,000 kWh	$0.030100	$0.080588	$0.050488	168%
	Sum Off-Peak >1,000 kWh	$0.030100	$0.080588	$0.050488	168%
	Win On-Peak First 500 kWh	$0.065200	$0.064008	-$0.001192	-2%
	Win On-Peak 501-1,000 kWh	$0.065200	$0.080588	$0.015388	24%
	Win On-Peak >1,000 kWh	$0.065200	$0.080588	$0.015388	24%
	Win Off-Peak First 500 kWh	$0.033000	$0.064008	$0.031008	94%
	Win Off-Peak 501-1,000 kWh	$0.033000	$0.080588	$0.047588	144%
	Win Off-Peak >1,000 kWh	$0.033000	$0.080588	$0.047588	144%
	Base Power Summer On-Peak kWh	$0.053198	$0.051660	-$0.001538	-3%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026750	$0.003552	15%
	Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
	Base Power Winter Off-peak kWh	$0.020698	$0.028092	$0.007394	36%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE4-70	**Lifeline Residential Time of Use (Frozen 1996 - Senior % Discount)**				
	Basic Service Charge Per Month	$8.78	$15.00	$6.22	71%
	Sum On-Peak First 500 kWh	$0.139300	$0.064008	-$0.075292	-54%
	Sum On-Peak 501-1,000 kWh	$0.139300	$0.080588	-$0.058712	-42%
	Sum On-Peak >1,000 kWh	$0.139300	$0.080588	-$0.058712	-42%
	Sum Shldr-Peak First 500 kWh	$0.074000	$0.064008	-$0.009992	-14%
	Sum Shldr-Peak 501-1,000 kWh	$0.074000	$0.080588	$0.006588	9%
	Sum Shldr-Peak >1,000 kWh	$0.074000	$0.080588	$0.006588	9%
	Sum Off-Peak First 500 kWh	$0.037900	$0.064008	$0.026108	69%
	Sum Off-Peak 501-1,000 kWh	$0.037900	$0.080588	$0.042688	113%
	Sum Off-Peak >1,000 kWh	$0.037900	$0.080588	$0.042688	113%
	Win On-Peak First 500 kWh	$0.092500	$0.064008	-$0.028492	-31%
	Win On-Peak 501-1,000 kWh	$0.092500	$0.080588	-$0.011912	-13%
	Win On-Peak >1,000 kWh	$0.092500	$0.080588	-$0.011912	-13%
	Win Off-Peak First 500 kWh	$0.024900	$0.064008	$0.039108	157%
	Win Off-Peak 501-1,000 kWh	$0.024900	$0.080588	$0.055688	224%
	Win Off-Peak >1,000 kWh	$0.024900	$0.080588	$0.055688	224%
	Base Power Summer On-Peak kWh	$0.055698	$0.051660	-$0.004038	-7%
	Base Power Summer Shoulder kWh	$0.048198	$0.051660	$0.003462	7%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026750	$0.003552	15%
	Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
	Base Power Winter Off-peak kWh	$0.020698	$0.028092	$0.007394	36%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE5-01	**Lifeline Residential Service Standard (Frozen Lifeline % Discount)**				
	Basic Service Charge Per Month	$6.90	$15.00	$8.10	117%
	Sum First 500 kWh	$0.061100	$0.064008	$0.002908	5%
	Sum 501-1,000 kWh	$0.061100	$0.080588	$0.019488	32%
	Sum >1,000 kWh	$0.061100	$0.080588	$0.019488	32%
	Win First 500 kWh	$0.057000	$0.064008	$0.007008	12%
	Win 501-1,000 kWh	$0.057000	$0.080588	$0.023588	41%
	Win >1,000 kWh	$0.057000	$0.080588	$0.023588	41%
	Base Power Summer kWh	$0.033198	$0.035868	$0.002670	8%
	Base Power Winter kWh	$0.025698	$0.032537	$0.006839	27%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE5-21	**Residential Time of Use (Frozen Lifeline % Discount)**				
	Basic Service Charge Per Month	$8.86	$15.00	$6.14	69%
	Sum On-Peak First 500 kWh	$0.078800	$0.064008	-$0.014792	-19%
	Sum On-Peak 501-1,000 kWh	$0.078800	$0.080588	$0.001788	2.3%
	Sum On-Peak >1,000 kWh	$0.078800	$0.080588	$0.001788	2.3%
	Sum Off-Peak First 500 kWh	$0.030100	$0.064008	$0.033908	112.7%
	Sum Off-Peak 501-1,000 kWh	$0.030100	$0.080588	$0.050488	168%
	Sum Off-Peak >1,000 kWh	$0.030100	$0.080588	$0.050488	168%
	Win On-Peak First 500 kWh	$0.065200	$0.064008	-$0.001192	-2%
	Win On-Peak 501-1,000 kWh	$0.065200	$0.080588	$0.015388	24%
	Win On-Peak >1,000 kWh	$0.065200	$0.080588	$0.015388	24%
	Win Off-Peak First 500 kWh	$0.033000	$0.064008	$0.031008	94%
	Win Off-Peak 501-1,000 kWh	$0.033000	$0.080588	$0.047588	144%
	Win Off-Peak >1,000 kWh	$0.033000	$0.080588	$0.047588	144%
	Base Power Summer On-Peak kWh	$0.053198	$0.051660	-$0.001538	-3%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026750	$0.003552	15%
	Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
	Base Power Winter Off-peak kWh	$0.020698	$0.028092	$0.007394	36%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE5-70	**Residential Time of Use (Frozen Lifeline % Discount)**				
	Basic Service Charge Per Month	$8.78	$15.00	$6.22	71%
	Sum On-Peak First 500 kWh	$0.139300	$0.064008	-$0.075292	-54%
	Sum On-Peak 501-1,000 kWh	$0.139300	$0.080588	-$0.058712	-42%
	Sum On-Peak >1,000 kWh	$0.139300	$0.080588	-$0.058712	-42%
	Sum Shldr-Peak First 500 kWh	$0.074000	$0.064008	-$0.009992	-14%
	Sum Shldr-Peak 501-1,000 kWh	$0.074000	$0.080588	$0.006588	9%
	Sum Shldr-Peak >1,000 kWh	$0.074000	$0.080588	$0.006588	9%
	Sum Off-Peak First 500 kWh	$0.037900	$0.064008	$0.026108	69%
	Sum Off-Peak 501-1,000 kWh	$0.037900	$0.080588	$0.042688	113%
	Sum Off-Peak >1,000 kWh	$0.037900	$0.080588	$0.042688	113%
	Win On-Peak First 500 kWh	$0.092500	$0.064008	-$0.028492	-31%
	Win On-Peak 501-1,000 kWh	$0.092500	$0.080588	-$0.011912	-13%
	Win On-Peak >1,000 kWh	$0.092500	$0.080588	-$0.011912	-13%
	Win Off-Peak First 500 kWh	$0.024900	$0.064008	$0.039108	157%
	Win Off-Peak 501-1,000 kWh	$0.024900	$0.080588	$0.055688	224%
	Win Off-Peak >1,000 kWh	$0.024900	$0.080588	$0.055688	224%
	Base Power Summer On-Peak kWh	$0.055698	$0.051660	-$0.004038	-7%
	Base Power Summer Shoulder kWh	$0.048198	$0.051660	$0.003462	7%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026750	$0.003552	15%
	Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
	Base Power Winter Off-peak kWh	$0.020698	$0.028092	$0.007394	36%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE6-01	**Residential Service Standard (Frozen Lifeline Flat Discount)**				
	Basic Service Charge Per Month	$6.90	$15.00	$8.10	117%
	Sum First 500 kWh	$0.061100	$0.064008	$0.002908	5%
	Sum 501-1,000 kWh	$0.061100	$0.080588	$0.019488	32%
	Sum >1,000 kWh	$0.061100	$0.080588	$0.019488	32%
	Win First 500 kWh	$0.057000	$0.064008	$0.007008	12%
	Win 501-1,000 kWh	$0.057000	$0.080588	$0.023588	41%
	Win >1,000 kWh	$0.057000	$0.080588	$0.023588	41%
	Base Power Summer kWh	$0.033198	$0.035868	$0.002670	8%
	Base Power Winter kWh	$0.025698	$0.032537	$0.006839	27%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE6-21	**Residential Time of Use (Frozen Lifeline Flat Discount)**				
	Basic Service Charge Per Month	$8.86	$15.00	$6.14	69%
	Sum On-Peak First 500 kWh	$0.078800	$0.064008	-$0.014792	-19%
	Sum On-Peak 501-1,000 kWh	$0.078800	$0.080588	$0.001788	2%
	Sum On-Peak >1,000 kWh	$0.078800	$0.080588	$0.001788	2%
	Sum Off-Peak First 500 kWh	$0.030100	$0.064008	$0.033908	113%
	Sum Off-Peak 501-1,000 kWh	$0.030100	$0.080588	$0.050488	168%
	Sum Off-Peak >1,000 kWh	$0.030100	$0.080588	$0.050488	168%
	Win On-Peak First 500 kWh	$0.065200	$0.064008	-$0.001192	-2%
	Win On-Peak 501-1,000 kWh	$0.065200	$0.080588	$0.015388	24%
	Win On-Peak >1,000 kWh	$0.065200	$0.080588	$0.015388	24%
	Win Off-Peak First 500 kWh	$0.033000	$0.064008	$0.031008	94%
	Win Off-Peak 501-1,000 kWh	$0.033000	$0.080588	$0.047588	144%
	Win Off-Peak >1,000 kWh	$0.033000	$0.080588	$0.047588	144%
	Base Power Summer On-Peak kWh	$0.053198	$0.051660	-$0.001538	-3%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026750	$0.003552	15%
	Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
	Base Power Winter Off-peak kWh	$0.020698	$0.028092	$0.007394	36%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE6-70	**Residential Time of Use (Frozen Lifeline Flat Discount)**				
	Basic Service Charge Per Month	$8.78	$15.00	$6.22	71%
	Sum On-Peak First 500 kWh	$0.139300	$0.064008	-$0.075292	-54%
	Sum On-Peak 501-1,000 kWh	$0.139300	$0.080588	-$0.058712	-42%
	Sum On-Peak >1,000 kWh	$0.139300	$0.080588	-$0.058712	-42%
	Sum Shldr-Peak First 500 kWh	$0.074000	$0.064008	-$0.009992	-14%
	Sum Shldr-Peak 501-1,000 kWh	$0.074000	$0.080588	$0.006588	9%
	Sum Shldr-Peak >1,000 kWh	$0.074000	$0.080588	$0.006588	9%
	Sum Off-Peak First 500 kWh	$0.037900	$0.064008	$0.026108	69%
	Sum Off-Peak 501-1,000 kWh	$0.037900	$0.080588	$0.042688	113%
	Sum Off-Peak >1,000 kWh	$0.037900	$0.080588	$0.042688	113%
	Win On-Peak First 500 kWh	$0.092500	$0.064008	-$0.028492	-31%
	Win On-Peak 501-1,000 kWh	$0.092500	$0.080588	-$0.011912	-13%
	Win On-Peak >1,000 kWh	$0.092500	$0.080588	-$0.011912	-13%
	Win Off-Peak First 500 kWh	$0.024900	$0.064008	$0.039108	157%
	Win Off-Peak 501-1,000 kWh	$0.024900	$0.080588	$0.055688	224%
	Win Off-Peak >1,000 kWh	$0.024900	$0.080588	$0.055688	224%
	Base Power Summer On-Peak kWh	$0.055698	$0.051660	-$0.004038	-7%
	Base Power Summer Shoulder kWh	$0.048198	$0.051660	$0.003462	7%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026750	$0.003552	15%
	Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
	Base Power Winter Off-peak kWh	$0.020698	$0.028092	$0.007394	36%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE6-201A	**Special Residential Service (Frozen Lifeline Flat Discount)**				
	Basic Service Charge Per Month	$6.90	$15.00	$8.10	117%
	Mid Sum First 500 kWh	$0.061100	$0.064008	$0.002908	5%
	Mid Sum 501-1,000 kWh	$0.061100	$0.080588	$0.019488	32%
	Mid Sum >1,000 kWh	$0.061100	$0.080588	$0.019488	32%
	Remain Sum First 500 kWh	$0.043600	$0.064008	$0.020408	47%
	Remain Sum 501-1,000 kWh	$0.043600	$0.080588	$0.036988	85%
	Remain Sum >1,000 kWh	$0.043600	$0.080588	$0.036988	85%
	Win First 500 kWh	$0.041300	$0.064008	$0.022708	55%
	Win 501-1,000 kWh	$0.041300	$0.080588	$0.039288	95%
	Win >1,000 kWh	$0.041300	$0.080588	$0.039288	95%
	Base Power Mid Summer kWh	$0.033198	$0.028694	-$0.004504	-14%
	Base Power Remaining Summer kWh	$0.033198	$0.000000	-$0.033198	-100%
	Base Power Winter kWh	$0.027198	$0.026030	-$0.001168	-4%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE6-201B	**Special Residential Service Time of Use (Frozen Lifeline Flat Discount)**				
	Basic Service Charge Per Month	$8.78	$15.00	$6.22	71%
	Mid Sum On-Peak First 500 kWh	$0.136900	$0.064008	-$0.072892	-53%
	Mid Sum On-Peak 501-1,000 kWh	$0.136900	$0.080588	-$0.056312	-41%
	Mid Sum On-Peak >1,000 kWh	$0.136900	$0.080588	-$0.056312	-41%
	Mid Sum Shlder-Peak First 500 kWh	$0.074700	$0.064008	-$0.010692	-14%
	Mid Sum Shldr-Peak 501-1,000 kWh	$0.074700	$0.080588	$0.005888	8%
	Mid Sum Shldr-Peak >1,000 kWh	$0.074700	$0.080588	$0.005888	8%
	Mid Sum Off-Peak First 500 kWh	$0.038300	$0.064008	$0.025708	67%
	Mid Sum Off-Peak 501-1,000 kWh	$0.038300	$0.080588	$0.042288	110%
	Mid Sum Off-Peak >1,000 kWh	$0.038300	$0.080588	$0.042288	110%
	Remain Sum On-Peak First 500 kWh	$0.099500	$0.000000	-$0.099500	-100%
	Remain Sum On-Peak 501-1,000 kWh	$0.099500	$0.000000	-$0.099500	-100%
	Remain Sum On-Peak >1,000 kWh	$0.099500	$0.000000	-$0.099500	-100%
	Remain Sum Shlder-Peak First 500 kWh	$0.048600	$0.000000	-$0.048600	-100%
	Remain Sum Shldr-Peak 501-1,000 kWh	$0.048600	$0.000000	-$0.048600	-100%
	Remain Sum Shldr-Peak >1,000 kWh	$0.048600	$0.000000	-$0.048600	-100%
	Remain Sum Off-Peak First 500 kWh	$0.025300	$0.000000	-$0.025300	-100%
	Remain Sum Off-Peak 501-1,000 kWh	$0.025300	$0.000000	-$0.025300	-100%
	Remain Sum Off-Peak >1,000 kWh	$0.025300	$0.000000	-$0.025300	-100%
	Win On-Peak First 500 kWh	$0.065200	$0.064008	-$0.001192	-2%
	Win On-Peak 501-1,000 kWh	$0.065200	$0.080588	$0.015388	24%
	Win On-Peak >1,000 kWh	$0.065200	$0.080588	$0.015388	24%
	Win Off-Peak First 500 kWh	$0.015300	$0.064008	$0.048708	318%
	Win Off-Peak 501-1,000 kWh	$0.015300	$0.080588	$0.065288	427%
	Win Off-Peak >1,000 kWh	$0.015300	$0.080588	$0.065288	427%
	Base Power Mid Summer On-Peak kWh	$0.055698	$0.043911	-$0.011787	-21%
	Base Power Mid Summer Shoulder kWh	$0.048198	$0.000000	-$0.048198	-100%
	Base Power Mid Summer Off-Peak kWh	$0.023198	$0.022738	-$0.000461	-2%
	Base Power Remaining Summer On-Peak kWh	$0.055698	$0.000000	-$0.055698	-100%
	Base Power Remaining Summer Shoulder kWh	$0.048198	$0.000000	-$0.048198	-100%
	Base Power Remaining Summer Off-Peak kWh	$0.023198	$0.000000	-$0.023198	-100%
	Base Power Winter On-Peak kWh	$0.040698	$0.028809	-$0.011889	-29%
	Base Power Winter Off-Peak kWh	$0.020698	$0.023878	$0.003180	15%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE8-01	**Residential Service Standard (Frozen Lifeline Medical % Discount)**				
	Basic Service Charge Per Month	$6.90	$15.00	$8.10	117%
	Sum First 500 kWh	$0.061100	$0.064008	$0.002908	5%
	Sum 501-1,000 kWh	$0.061100	$0.080588	$0.019488	32%
	Sum >1,000 kWh	$0.061100	$0.080588	$0.019488	32%
	Win First 500 kWh	$0.057000	$0.064008	$0.007008	12%
	Win 501-1,000 kWh	$0.057000	$0.080588	$0.023588	41%
	Win >1,000 kWh	$0.057000	$0.080588	$0.023588	41%
	Base Power Summer kWh	$0.033198	$0.035868	$0.002670	8%
	Base Power Winter kWh	$0.025698	$0.032537	$0.006839	27%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE8-21	**Residential Time of Use (Frozen Lifeline Medical % Discount)**				
	Basic Service Charge Per Month	$8.86	$15.00	$6.14	69%
	Sum On-Peak First 500 kWh	$0.078800	$0.064008	-$0.014792	-19%
	Sum On-Peak 501-1,000 kWh	$0.078800	$0.080588	$0.001788	2%
	Sum On-Peak >1,000 kWh	$0.078800	$0.080588	$0.001788	2%
	Sum Off-Peak First 500 kWh	$0.030100	$0.064008	$0.033908	113%
	Sum Off-Peak 501-1,000 kWh	$0.030100	$0.080588	$0.050488	168%
	Sum Off-Peak >1,000 kWh	$0.030100	$0.080588	$0.050488	168%
	Win On-Peak First 500 kWh	$0.065200	$0.064008	-$0.001192	-2%
	Win On-Peak 501-1,000 kWh	$0.065200	$0.080588	$0.015388	24%
	Win On-Peak >1,000 kWh	$0.065200	$0.080588	$0.015388	24%
	Win Off-Peak First 500 kWh	$0.033000	$0.064008	$0.031008	94%
	Win Off-Peak 501-1,000 kWh	$0.033000	$0.080588	$0.047588	144%
	Win Off-Peak >1,000 kWh	$0.033000	$0.080588	$0.047588	144%
	Base Power Summer On-Peak kWh	$0.053198	$0.051660	-$0.001538	-3%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026750	$0.003552	15%
	Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
	Base Power Winter Off-peak kWh	$0.020698	$0.028092	$0.007394	36%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE8-70	**Residential Time of Use (Frozen Lifeline Medical % Discount)**				
	Basic Service Charge Per Month	$8.78	$15.00	$6.22	71%
	Sum On-Peak First 500 kWh	$0.139300	$0.064008	-$0.075292	-54%
	Sum On-Peak 501-1,000 kWh	$0.139300	$0.080588	-$0.058712	-42%
	Sum On-Peak >1,000 kWh	$0.139300	$0.080588	-$0.058712	-42%
	Sum Shldr-Peak First 500 kWh	$0.074000	$0.064008	-$0.009992	-14%
	Sum Shldr-Peak 501-1,000 kWh	$0.074000	$0.080588	$0.006588	9%
	Sum Shldr-Peak >1,000 kWh	$0.074000	$0.080588	$0.006588	9%
	Sum Off-Peak First 500 kWh	$0.037900	$0.064008	$0.026108	69%
	Sum Off-Peak 501-1,000 kWh	$0.037900	$0.080588	$0.042688	113%
	Sum Off-Peak >1,000 kWh	$0.037900	$0.080588	$0.042688	113%
	Win On-Peak First 500 kWh	$0.092500	$0.064008	-$0.028492	-31%
	Win On-Peak 501-1,000 kWh	$0.092500	$0.080588	-$0.011912	-13%
	Win On-Peak >1,000 kWh	$0.092500	$0.080588	-$0.011912	-13%
	Win Off-Peak First 500 kWh	$0.024900	$0.064008	$0.039108	157%
	Win Off-Peak 501-1,000 kWh	$0.024900	$0.080588	$0.055688	224%
	Win Off-Peak >1,000 kWh	$0.024900	$0.080588	$0.055688	224%
	Base Power Summer On-Peak kWh	$0.055698	$0.051660	-$0.004038	-7%
	Base Power Summer Shoulder kWh	$0.048198	$0.051660	$0.003462	7%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026750	$0.003552	15%
	Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
	Base Power Winter Off-peak kWh	$0.020698	$0.028092	$0.007394	36%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE8-201A	**Special Residential Service (Frozen Lifeline Medical % Discount)**				
	Basic Service Charge Per Month	$6.90	$15.00	$8.10	117%
	Mid Sum First 500 kWh	$0.061100	$0.064008	$0.002908	5%
	Mid Sum 501-1,000 kWh	$0.061100	$0.080588	$0.019488	32%
	Mid Sum >1,000 kWh	$0.061100	$0.080588	$0.019488	32%
	Remain Sum First 500 kWh	$0.043600	$0.000000	-$0.043600	-100%
	Remain Sum 501-1,000 kWh	$0.043600	$0.000000	-$0.043600	-100%
	Remain Sum >1,000 kWh	$0.043600	$0.000000	-$0.043600	-100%
	Win First 500 kWh	$0.041300	$0.064008	$0.022708	55%
	Win 501-1,000 kWh	$0.041300	$0.080588	$0.039288	95%
	Win >1,000 kWh	$0.041300	$0.080588	$0.039288	95%
	Base Power Mid Summer kWh	$0.033198	$0.028694	-$0.004504	-14%
	Base Power Remaining Summer kWh	$0.033198	$0.000000	-$0.033198	-100%
	Base Power Winter kWh	$0.027198	$0.026030	-$0.001168	-4%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE6-01BC	**Residential Service Standard (Frozen Lifeline Flat Discount) Bright Community Solar**				
	Basic Service Charge Per Month	$6.90	$15.00	$8.10	117%
	Sum First 500 kWh	$0.061100	$0.064008	$0.002908	5%
	Sum 501-1,000 kWh	$0.061100	$0.080588	$0.019488	32%
	Sum >1,000 kWh	$0.061100	$0.080588	$0.019488	32%
	Win First 500 kWh	$0.057000	$0.064008	$0.007008	12%
	Win 501-1,000 kWh	$0.057000	$0.080588	$0.023588	41%
	Win >1,000 kWh	$0.057000	$0.080588	$0.023588	41%
	Base Power Summer kWh	$0.033198	$0.035868	$0.002670	8%
	Base Power Winter kWh	$0.025698	$0.032537	$0.006839	27%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-R-01LL	**Residential Service Standard**				
	Basic Service Charge Per Month	$10.00	$15.00	$5.00	50%
	Sum First 500 kWh	$0.056200	$0.064008	$0.007808	14%
	Sum 501-1,000 kWh	$0.067200	$0.080588	$0.013388	20%
	Sum 1,001-3,500 kWh	$0.079800	$0.080588	$0.000788	1%
	Sum>3,500 kWh	$0.088200	$0.080588	-$0.007612	-9%
	Win First 500 kWh	$0.056200	$0.064008	$0.007808	14%
	Win 501-1,000 kWh	$0.065200	$0.080588	$0.015388	24%
	Win 1,001-3,500 kWh	$0.078100	$0.080588	$0.002488	3%
	Win>3,500 kWh	$0.087100	$0.080588	-$0.006512	-7%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-R01LB	**Residential Service R-01 Bright Community Solar**				
	Basic Service Charge Per Month	$10.00	$15.00	$5.00	50%
	Sum First 500 kWh	$0.056200	$0.064008	$0.007808	14%
	Sum 501-1,000 kWh	$0.067200	$0.080588	$0.013388	20%
	Sum 1,001-3,500 kWh	$0.079800	$0.080588	$0.000788	1%
	Sum>3,500 kWh	$0.088200	$0.080588	-$0.007612	-9%
	Win First 500 kWh	$0.056200	$0.064008	$0.007808	14%
	Win 501-1,000 kWh	$0.065200	$0.080588	$0.015388	24%
	Win 1,001-3,500 kWh	$0.078100	$0.080588	$0.002488	3%
	Win>3,500 kWh	$0.087100	$0.080588	-$0.006512	-7%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-201AL	**Special Residential Electric Service**				
	Basic Service Charge Per Month	$10.00	$15.00	$5.00	50%
	Sum First 500 kWh	$0.050600	$0.064008	$0.013408	26%
	Sum 501-1,000 kWh	$0.060500	$0.080588	$0.020088	33%
	Sum 1,001-3,500 kWh	$0.071800	$0.080588	$0.008788	12%
	Sum>3,500 kWh	$0.079400	$0.080588	$0.001188	1%
	Win First 500 kWh	$0.050600	$0.064008	$0.013408	26%
	Win 501-1,000 kWh	$0.058700	$0.080588	$0.021888	37%
	Win 1,001-3,500 kWh	$0.070300	$0.080588	$0.010288	15%
	Win>3,500 kWh	$0.078400	$0.080588	$0.002188	3%
	Base Power Summer kWh	$0.035111	$0.028694	-$0.006417	-18%
	Base Power Winter kWh	$0.031532	$0.026030	-$0.005502	-17%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-201BL	**Residential Time of Use**				
	Basic Service Charge Per Month	$11.50	$15.00	$3.50	30%
	Sum On-peak First 500 kWh	$0.056800	$0.064008	$0.007208	13%
	Sum On-peak 501-1,000 kWh	$0.056800	$0.080588	$0.023788	42%
	Sum On-peak1,001-3,500 kWh	$0.056800	$0.080588	$0.023788	42%
	Sum On-peak >3,500 kWh	$0.056800	$0.080588	$0.023788	42%
	Sum Off-peak First 500 kWh	$0.044000	$0.064008	$0.020008	45%
	Sum Off-peak 501-1,000 kWh	$0.044000	$0.080588	$0.036588	83%
	Sum Off-peak1,001-3,500 kWh	$0.044000	$0.080588	$0.036588	83%
	Sum Off-peak >3,500 kWh	$0.044000	$0.080588	$0.036588	83%
	Win On-peak First 500 kWh	$0.048300	$0.064008	$0.015708	33%
	Win On-peak 501-1,000 kWh	$0.048300	$0.080588	$0.032288	67%
	Win On-peak1,001-3,500 kWh	$0.048300	$0.080588	$0.032288	67%
	Win On-peak >3,500 kWh	$0.048300	$0.080588	$0.032288	67%
	Win Off-peak First 500 kWh	$0.035500	$0.064008	$0.028508	80%
	Win Off-peak 501-1,000 kWh	$0.035500	$0.080588	$0.045088	127%
	Win Off-peak1,001-3,500 kWh	$0.035500	$0.080588	$0.045088	127%
	Win Off-peak >3,500 kWh	$0.035500	$0.080588	$0.045088	127%
	Base Power Summer On-Peak kWh	$0.050669	$0.041328	-$0.009341	-18%
	Base Power Summer Off-Peak kWh	$0.026679	$0.021400	-$0.005279	-20%
	Base Power Winter On-peak kWh	$0.032893	$0.027114	-$0.005779	-18%
	Base Power Winter Off-peak kWh	$0.027092	$0.022474	-$0.004618	-17%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-R80LL	**Residential Time of Use**				
	Basic Service Charge Per Month	$11.50	$15.00	$3.50	30%
	Sum On-peak First 500 kWh	$0.066800	$0.064008	-$0.002792	-4%
	Sum On-peak 501-1,000 kWh	$0.066800	$0.080588	$0.013788	21%
	Sum On-peak1,001-3,500 kWh	$0.066800	$0.080588	$0.013788	21%
	Sum On-peak >3,500 kWh	$0.066800	$0.080588	$0.013788	21%
	Sum Off-peak First 500 kWh	$0.051800	$0.064008	$0.012208	24%
	Sum Off-peak 501-1,000 kWh	$0.051800	$0.080588	$0.028788	56%
	Sum Off-peak1,001-3,500 kWh	$0.051800	$0.080588	$0.028788	56%
	Sum Off-peak >3,500 kWh	$0.051800	$0.080588	$0.028788	56%
	Win On-peak First 500 kWh	$0.056800	$0.064008	$0.007208	13%
	Win On-peak 501-1,000 kWh	$0.056800	$0.080588	$0.023788	42%
	Win On-peak1,001-3,500 kWh	$0.056800	$0.080588	$0.023788	42%
	Win On-peak >3,500 kWh	$0.056800	$0.080588	$0.023788	42%
	Win Off-peak First 500 kWh	$0.041800	$0.064008	$0.022208	53%
	Win Off-peak 501-1,000 kWh	$0.041800	$0.080588	$0.038788	93%
	Win Off-peak1,001-3,500 kWh	$0.041800	$0.080588	$0.038788	93%
	Win Off-peak >3,500 kWh	$0.041800	$0.080588	$0.038788	93%
	Base Power Summer On-Peak kWh	$0.050669	$0.051660	$0.000991	2%
	Base Power Summer Off-Peak kWh	$0.026679	$0.026750	$0.000071	0%
	Base Power Winter On-peak kWh	$0.032893	$0.033893	$0.001000	3%
	Base Power Winter Off-peak kWh	$0.027092	$0.028092	$0.001000	4%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-R8LL	**Residential Time of Use Super Peak Lifeline**				
	Basic Service Charge Per Month	$11.50	$15.00	$3.50	30%
	Sum On-peak First 500 kWh	$0.097100	$0.064008	-$0.033092	-34%
	Sum On-peak 501-1,000 kWh	$0.097100	$0.080588	-$0.016512	-17%
	Sum On-peak1,001-3,500 kWh	$0.120100	$0.080588	-$0.039512	-33%
	Sum On-peak >3,500 kWh	$0.120100	$0.080588	-$0.039512	-33%
	Sum Off-peak First 500 kWh	$0.048500	$0.064008	$0.015508	32%
	Sum Off-peak 501-1,000 kWh	$0.048500	$0.080588	$0.032088	66%
	Sum Off-peak1,001-3,500 kWh	$0.071500	$0.080588	$0.009088	13%
	Sum Off-peak >3,500 kWh	$0.071500	$0.080588	$0.009088	13%
	Win On-peak First 500 kWh	$0.089100	$0.064008	-$0.025092	-28%
	Win On-peak 501-1,000 kWh	$0.089100	$0.080588	-$0.008512	-10%
	Win On-peak1,001-3,500 kWh	$0.112100	$0.080588	-$0.031512	-28%
	Win On-peak >3,500 kWh	$0.112100	$0.080588	-$0.031512	-28%
	Win Off-peak First 500 kWh	$0.038500	$0.064008	$0.025508	66%
	Win Off-peak 501-1,000 kWh	$0.038500	$0.080588	$0.042088	109%
	Win Off-peak1,001-3,500 kWh	$0.061500	$0.080588	$0.019088	31%
	Win Off-peak >3,500 kWh	$0.061500	$0.080588	$0.019088	31%
	Base Power Summer On-Peak kWh	$0.080100	$0.081060	$0.000960	1%
	Base Power Summer Off-Peak kWh	$0.022200	$0.022750	$0.000550	2%
	Base Power Winter On-peak kWh	$0.040200	$0.041293	$0.001093	3%
	Base Power Winter Off-peak kWh	$0.020500	$0.021492	$0.000992	5%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-PESXX	**Prepay Electric Service**				
	Basic Service Charge Per Day	N/M	$0.6670	N/M	N/M
	Sum First 20 kWh Per Day	N/M	$0.064008	N/M	N/M
	Sum >20 kWh Per Day	N/M	$0.080588	N/M	N/M
	Win First 20 kWh Per Day	N/M	$0.064008	N/M	N/M
	Win >20 kWh Per Day	N/M	$0.080588	N/M	N/M
	Base Power Summer kWh	N/M	$0.035868	N/M	N/M
	Base Power Winter kWh	N/M	$0.032537	N/M	N/M
	PPFAC Charge kWh	N/M	$0.000000	N/M	N/M
TE-GS10	**Small General Service**				
	Basic Service Charge Single Phase Per Mo.	$15.50	$27.00	$11.50	74%
	Basic Service Charge Three Phase Per Mo.	$20.50	$32.00	$11.50	56%
	Sum First 500 kWh	$0.077000	$0.076899	-$0.000101	0%
	Sum >500 kWh	$0.097800	$0.096899	-$0.000901	-1%
	Win First 500 kWh	$0.057000	$0.056900	-$0.000100	0%
	Win >500 kWh	$0.079000	$0.077900	-$0.001100	-1%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-GSXX	**Small General Service Demand**				
	Basic Service Charge Per Month	N/M	$27.00	N/M	N/M
	Demand 0-7 kW	N/M	$9.60	N/M	N/M
	Demand > 7 kW	N/M	$13.75	N/M	N/M
	Sum kWh	N/M	$0.057770	N/M	N/M
	Win kWh	N/M	$0.047770	N/M	N/M
	Base Power Summer kWh	N/M	$0.035868	N/M	N/M
	Base Power Winter kWh	N/M	$0.032537	N/M	N/M
	PPFAC Charge kWh	N/M	$0.000000	N/M	N/M
TE-GS11	**Mobile Home Park Service (FROZEN)**				
	Basic Service Charge Single Phase Per Mo.	$15.50	$27.00	$11.50	74%
	Basic Service Charge Three Phase Per Mo.	$20.50	$32.00	$11.50	56%
	Sum kWh	$0.082000	$0.080399	-$0.001601	-2%
	Win kWh	$0.062000	$0.080399	$0.018399	30%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-GS76	**Small General Service Time of Use**				
	Basic Service Charge	$17.50	$27.00	$9.50	54%
	Sum On-peak First 500 kWh	$0.099100	$0.076899	-$0.022201	-22%
	Sum On-peak >500 kWh	$0.099100	$0.096899	-$0.002201	-2%
	Sum Off-peak First 500 kWh	$0.084900	$0.076899	-$0.008001	-9%
	Sum Off-peak >500 kWh	$0.084900	$0.096899	$0.011999	14%
	Winter On-peak First 500 kWh	$0.081400	$0.056900	-$0.024500	-30%
	Winter On-peak >500 kWh	$0.081400	$0.077900	-$0.003500	-4%
	Winter Off-Peak First 500 kWh	$0.064900	$0.056900	-$0.008000	-12%
	Winter Off-Peak >500 kWh	$0.064900	$0.077900	$0.013000	20%
	Base Power Summer On-Peak kWh	$0.050669	$0.051660	$0.000991	2%
	Base Power Summer Off-Peak kWh	$0.026679	$0.026750	$0.000071	0%
	Base Power Winter On-peak kWh	$0.032893	$0.033893	$0.001000	3%
	Base Power Winter Off-peak kWh	$0.027092	$0.028092	$0.001000	4%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
Solar Block Rate for Small General Service Rate GS-10		$0.053274	$0.054197	$0.000923	2%
TE-GSXXX	**Small General Service Demand Time of Use**				
	Basic Service Charge Per Month	N/M	$27.00	N/M	N/M
	Demand 0-7 kW	N/M	$9.60	N/M	N/M
	Demand > 7 kW	N/M	$13.75	N/M	N/M
	Sum On-peak kWh	N/M	$0.057770	N/M	N/M
	Sum Off-peak kWh	N/M	$0.057770	N/M	N/M
	Win On-peak kWh	N/M	$0.047770	N/M	N/M
	Win Off-peak kWh	N/M	$0.047770	N/M	N/M
	Base Power Summer On-Peak kWh	N/M	$0.051660	N/M	N/M
	Base Power Summer Off-Peak kWh	N/M	$0.026750	N/M	N/M
	Base Power Winter On-peak kWh	N/M	$0.033893	N/M	N/M
	Base Power Winter Off-peak kWh	N/M	$0.028092	N/M	N/M
	PPFAC Charge kWh	N/M	$0.000000	N/M	N/M
TE-G10BC	**General Service Bright Community Solar**				
	Basic Service Charge Single Phase Per Month	$15.50	$27.00	$11.50	74%
	Basic Service Charge Three Phase Per Month	$20.50	$32.00	$11.50	56%
	Sum First 500 kWh	$0.077000	$0.076899	-$0.000101	0%
	Sum>500 kWh	$0.097800	$0.096899	-$0.000901	-1%
	Winter First 500 kWh 0568	$0.057000	$0.056900	-$0.000100	0%
	Winter >500 kWh 0788	$0.079000	$0.077900	-$0.001100	-1%
	Winter First 500 kWh 0570	$0.057000	$0.000000	-$0.057000	-100%
	Winter >500 kWh 0790	$0.079000	$0.000000	-$0.079000	-100%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	Solar Blocks kWh_2011	$0.028475	$0.028475	$0.000000	0%
	Solar Blocks kWh_2013	$0.033274	$0.033274	$0.000000	0%
	Solar Blocks kWh_20xx	$0.028475	$0.028475	$0.000000	0%
	Credited Solar Blocks kWh_2011	-$0.028475	-$0.028475	$0.000000	0%
	Credited Solar Blocks kWh_2013	-$0.033274	-$0.033274	$0.000000	0%
	Credited Solar Blocks kWh_20xx	-$0.028475	-$0.028475	$0.000000	0%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase	
				$	%
TE-GSM10	**Small General Service (Municipal Transitional Adjustment)**				
	Basic Service Charge Single Phase Per Month	$15.50	$27.00	$11.50	74%
	Basic Service Charge Three Phase Per Month	$20.50	$32.00	$11.50	56%
	Sum First 500 kWh	$0.077000	$0.076899	-$0.000101	0%
	Sum>500 kWh	$0.097800	$0.096899	-$0.000901	-1%
	Win First 500 kWh	$0.057000	$0.056900	-$0.000100	0%
	Win>500 kWh	$0.079000	$0.077900	-$0.001100	-1%
	Transitional Adjustment	16.50%	0.00%	-$0.165000	-100%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-G10MBC	**General Service (Municipal Transitional Adjustment) Bright Community Solar**				
	Basic Service Charge Three Phase Per Month	$20.50	$27.00	$6.50	32%
	Sum First 500 kWh	$0.077000	$0.076899	-$0.000101	0%
	Sum>500 kWh	$0.097800	$0.096899	-$0.000901	-1%
	Win First 500 kWh	$0.057000	$0.056900	-$0.000100	0%
	Win>500 kWh	$0.079000	$0.077900	-$0.001100	-1%
	Transitional Adjustment	16.50%	0.00%	-$0.165000	-100%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
	RT 43 Water Pumping				
TE-GS36	GS-36 (43) Water Pumping-Firm Service				
	Basic Service Charge Per Mo.	$15.50	$27.00	$11.50	74%
	Sum kWh	$0.068000	$0.073299	$0.005299	8%
	Win kWh	$0.048000	$0.056999	$0.008999	19%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-GS37	GS-37 Com Water Pumping-Firm w/ Primary Voltage Discount				
	Basic Service Charge Per Mo.	$15.50	$27.00	$11.50	74%
	Sum kWh	$0.064600	$0.069634	$0.005034	8%
	Win kWh	$0.045600	$0.054149	$0.008549	19%
	Base Power Summer kWh	$0.033355	$0.034075	$0.000719	2%
	Base Power Winter kWh	$0.029955	$0.030910	$0.000955	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-GS38	GS-38 (43) Water Pumping-Interruptible Serv				
	Basic Service Charge Per Mo.	$15.50	$27.00	$11.50	74%
	Sum kWh	$0.042000	$0.047300	$0.005300	13%
	Win kWh	$0.027000	$0.036000	$0.009000	33%
	Base Power Summer kWh	$0.031310	$0.032100	$0.000790	3%
	Base Power Winter kWh	$0.028420	$0.029400	$0.000980	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-GS39	GS-39 (43) Water Pumping-Interupt w/Primary Voltage Discount				
	Basic Service Charge Per Mo.	$15.50	$27.00	$11.50	74%
	Sum kWh	$0.039900	$0.044900	$0.005000	13%
	Win kWh	$0.025650	$0.034200	$0.008550	33%
	Base Power Summer kWh	$0.029745	$0.030495	$0.000750	3%
	Base Power Winter kWh	$0.026999	$0.027930	$0.000931	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-MGS	**Medium General Service**				
	Basic Service Charge Per Month	N/M	$40.00	N/M	N/M
	Summer Demand Charge Per kW	N/M	$6.75	N/M	N/M
	Winter Demand Charge Per kW	N/M	$3.65	N/M	N/M
	Summer kWh	N/M	$0.082899	N/M	N/M
	Winter kWh	N/M	$0.069899	N/M	N/M
	Base Power Summer kWh	N/M	$0.035868	N/M	N/M
	Base Power Winter kWh	N/M	$0.032537	N/M	N/M
	PPFAC Charge kWh	N/M	$0.000000	N/M	N/M
Solar Block Rate for Medium General Service Rate MGS		$0.053227	0.05418		

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-MGSTOU	**Medium General Service TOU**				
	Basic Service Charge Per Month	N/M	$40.00	N/M	N/M
	Demand Summer On-Peak per kW	N/M	$7.75	N/M	N/M
	Demand Summer Off-Peak Excess Per kW	N/M	$3.45	N/M	N/M
	Demand Winter On-Peak Per kW	N/M	$3.35	N/M	N/M
	Demand Winter Off-Peak Excess Per kW	N/M	$2.85	N/M	N/M
	Summer On-Peak kWh	N/M	$0.109499	N/M	N/M
	Summer Off-Peak kWh	N/M	$0.066899	N/M	N/M
	Winter On-Peak kWh	N/M	$0.109499	N/M	N/M
	Winter Off-Peak kWh	N/M	$0.066899	N/M	N/M
	Base Power Summer On-Peak kWh	N/M	$0.051660	N/M	N/M
	Base Power Summer Off-Peak kWh	N/M	$0.026750	N/M	N/M
	Base Power Winter On-peak kWh	N/M	$0.033893	N/M	N/M
	Base Power Winter Off-peak kWh	N/M	$0.028092	N/M	N/M
	PPFAC Charge kWh	N/M	$0.000000	N/M	N/M
TE-MGSBC	**Medium General Service Bright Community solar**				
	Basic Service Charge Per Month	N/M	$40.00	N/M	N/M
	Summer Demand Charge Per kW	N/M	$6.75	N/M	N/M
	Winter Demand Charge Per kW	N/M	$3.65	N/M	N/M
	Summer kWh	N/M	$0.082899	N/M	N/M
	Winter kWh	N/M	$0.069899	N/M	N/M
	Base Power Summer kWh	N/M	$0.035868	N/M	N/M
	Base Power Winter kWh	N/M	$0.032537	N/M	N/M
	PPFAC Charge kWh	N/M	$0.000000	N/M	N/M
TE-LGS13	**Large General Service**				
	Basic Service Charge Per Month	$775.00	$950.00	$175.00	23%
	Demand Charge Per kW	$15.25	$17.55	$2.30	15%
	Summer kWh	$0.0192	$0.0185	-$0.000700	-4%
	Winter kWh	$0.0134	$0.0143	$0.000900	7%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-LG85	**Large General Service TOU**				
	Basic Service Charge Per Month	$950.00	$950.00	$0.00	0%
	Demand Summer On-Peak per kW	$14.55	$22.15	$7.60	52%
	Demand Summer Off-Peak Per kW	$10.92	$10.92	$0.00	0%
	Demand Winter On-Peak Per kW	$11.59	$18.50	$6.91	60%
	Demand Winter Off-Peak Per kW	$9.10	$9.10	$0.00	0%
	Summer On-Peak kWh	$0.008600	$0.018540	$0.009940	116%
	Summer Off-Peak kWh	$0.006000	$0.012700	$0.006700	112%
	Winter On-Peak kWh	$0.003000	$0.007100	$0.004100	137%
	Winter Off-Peak kWh	$0.000500	$0.001250	$0.000750	150%
	Base Power Summer On-Peak kWh	$0.050669	$0.051660	$0.000991	2%
	Base Power Summer Off-Peak kWh	$0.026679	$0.026750	$0.000071	0%
	Base Power Winter On-peak kWh	$0.032893	$0.033893	$0.001000	3%
	Base Power Winter Off-peak kWh	$0.027092	$0.028092	$0.001000	4%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-L13BC	**Large General Service Brigh Community Solar**				
	Basic Service Charge Per Month	$775.00	$950.00	$175.00	23%
	Demand Charge Per kW	$15.25	$17.55	$2.30	15%
	Summer kWh	$0.0192	$0.0185	-$0.000700	-4%
	Winter kWh	$0.0134	$0.0143	$0.000900	7%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	Solar_Blocks_kWh_053227_2P	$0.033227	$0.033227	$0.000000	0%
	Solar_Blocks_kWh_039371_1_1P	$0.029371	$0.029371	$0.000000	0%
	Credited_Blocks_kWh_039371_1_1P	-$0.029371	-$0.029371	$0.000000	0%
	Solar_Blocks_kWh_039371_2_1P	$0.029371	$0.029371	$0.000000	0%
	Credited_Blocks_kWh_039371_2_1P	-$0.029371	-$0.029371	$0.000000	0%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-LLP14	**Large Light & Power**		TARIFF CLOSED	TARIFF CLOSED	
	Basic Service Charge	$1,800.00	N/M	N/M	N/M
	Demand Charge	21.98	N/M	N/M	N/M
	Summer kWh	0.0032	N/M	N/M	N/M
	Winter kWh	0.0021	N/M	N/M	N/M
	Base Power Summer kWh	0.031611	N/M	N/M	N/M
	Base Power Winter kWh	0.028388	N/M	N/M	N/M
	PPFAC Charge kWh	$0.006820	N/M	N/M	N/M
TE-LLP90	Large Power Service Time of Use				
	Basic Service Charge Per Month	$2,000.00	$10,000.00	$8,000.00	400%
	Demand Summer On-Peak per kW	$20.49	$22.60	$2.11	10%
	Demand Summer Off-Peak Excess Per kW	$12.49	$14.69	$2.20	18%
	Demand Winter On-Peak Per kW	$15.49	$17.06	$1.57	10%
	Demand Winter Off-Peak Excess Per kW	$9.99	$14.58	$4.59	46%
	Summer On-Peak kWh	$0.006900	$0.007400	$0.000500	7%
	Summer Off-Peak kWh	$0.006500	$0.007400	$0.000900	14%
	Winter On-Peak kWh	$0.007500	$0.007400	-$0.000100	-1%
	Winter Off-Peak kWh	$0.007100	$0.007400	$0.000300	4%
	Base Power Summer On-Peak kWh	$0.045568	$0.049077	$0.003509	8%
	Base Power Summer Off-Peak kWh	$0.023985	$0.025413	$0.001428	6%
	Base Power Winter On-peak kWh	$0.029581	$0.032198	$0.002617	9%
	Base Power Winter Off-peak kWh	$0.024352	$0.026687	$0.002335	10%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-138	Transmission Service Rate 138kV				
	Basic Service Charge Per Month	N/M	$15,000.00	N/M	N/M
	Demand Summer On-Peak per kW	N/M	$22.00	N/M	N/M
	Demand Summer Off-Peak Excess Per kW	N/M	$14.69	N/M	N/M
	Demand Winter On-Peak Per kW	N/M	$17.06	N/M	N/M
	Demand Winter Off-Peak Excess Per kW	N/M	$14.58	N/M	N/M
	Summer On-Peak kWh	N/M	$0.007400	N/M	N/M
	Summer Off-Peak kWh	N/M	$0.007400	N/M	N/M
	Winter On-Peak kWh	N/M	$0.007400	N/M	N/M
	Winter Off-Peak kWh	N/M	$0.007400	N/M	N/M
	Base Power Summer On-Peak kWh	N/M	$0.048044	N/M	N/M
	Base Power Summer Off-Peak kWh	N/M	$0.024878	N/M	N/M
	Base Power Winter On-peak kWh	N/M	$0.031520	N/M	N/M
	Base Power Winter Off-peak kWh	N/M	$0.026126	N/M	N/M
	PPFAC Charge kWh	N/M	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-P41&P47	P41 Traffic Signal & Street Lighting				
	Basic Service Charge Per Month	$0.00	$0.00	$0.00	0%
	All Delivery kWh	$0.047600	$0.054000	$0.006400	13%
	Base Power Summer kWh	$0.035111	$0.035868	$0.000757	2%
	Base Power Winter kWh	$0.031532	$0.032537	$0.001005	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-P50	Lighting Service				
TE-R51 + TE-R5	100OH	$8.19	$9.97	$1.78	22%
TE-C52 & 52A	100UG	$23.72	$28.87	$5.15	22%
	250OH	$12.29	$14.96	$2.67	22%
	250UG	$27.82	$33.86	$6.04	22%
	400OH	$18.70	$22.76	$4.06	22%
	400UG	$34.23	$41.66	$7.43	22%
	55OH	$8.19	$9.97	$1.78	22%
	55P	$8.19	$9.97	$1.78	22%
	55UG	$23.72	$28.87	$5.15	22%
	70UG	$23.72	$28.87	$5.15	22%
	Pole	$2.86	$3.48	$0.62	22%
	Base Power				
	100OH	$1.34	$1.36	$0.02	1%
	100UG	$1.34	$1.36	$0.02	1%
	250OH	$3.36	$3.42	$0.06	2%
	250UG	$3.36	$3.42	$0.06	2%
	400OH	$5.38	$5.47	$0.09	2%
	400UG	$5.38	$5.47	$0.09	2%
	55OH	$0.85	$0.86	$0.01	1%
	55P	$0.85	$0.86	$0.01	1%
	55UG	$0.85	$0.86	$0.01	1%
	70UG	$0.94	$0.96	$0.02	2%

EXHIBIT HS-8

EXHIBIT HS-8

RESIDENTIAL SERVICE RATE R-01

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05620	$0.06520	$0.07810	$0.08710	$0.031532	$0.00682	
Small	520	500	20	0	0	$10.00	$28.10	$1.30	$0.00	$0.00	$16.40	$3.55	$59.35
Medium	840	500	340	0	0	$10.00	$28.10	$22.17	$0.00	$0.00	$26.49	$5.73	$92.49
Large	1,250	500	500	250	0	$10.00	$28.10	$32.60	$19.53	$0.00	$39.42	$8.53	$138.18
XLg	1,564	500	500	564	0	$10.00	$28.10	$32.60	$44.05	$0.00	$49.32	$10.67	$174.74
AnnAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78
ResAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill		
		500	1000	>1000			500	1000	>1000					$ Change	% Change
						$15.00	$0.06401	$0.08059	$0.08059		$0.032537	$0.00000			
Small	520	500	20	0		$15.00	$32.00	$1.61	$0.00		$16.92	$0.00	$65.53	$6.18	10.4%
Medium	840	500	340	0		$15.00	$32.00	$27.40	$0.00		$27.33	$0.00	$101.73	$9.24	10.0%
Large	1,250	500	500	250		$15.00	$32.00	$40.29	$20.15		$40.67	$0.00	$148.11	$9.93	7.2%
XLg	1,564	500	500	564		$15.00	$32.00	$40.29	$45.45		$50.89	$0.00	$183.63	$8.89	5.1%
AnnAvg	785	500	285	0		$15.00	$32.00	$22.97	$0.00		$25.54	$0.00	$95.51	$8.73	10.1%
ResAvg	785	500	285	0		$15.00	$32.00	$22.97	$0.00		$25.54	$0.00	$95.51	$8.73	10.1%

EXHIBIT HS-8

RESIDENTIAL SERVICE RATE R-01

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05620	$0.06720	$0.07980	$0.08820	$0.035111	$0.00682	
Small	822	500	322	0	0	$10.00	$28.10	$21.64	$0.00	$0.00	$28.86	$5.61	$94.21
Medium	1,384	500	500	384	0	$10.00	$28.10	$33.60	$30.64	$0.00	$48.59	$9.44	$160.37
Large	1,997	500	500	997	0	$10.00	$28.10	$33.60	$79.56	$0.00	$70.12	$13.62	$235.00
XLg	2,430	500	500	1,430	0	$10.00	$28.10	$33.60	$114.11	$0.00	$85.32	$16.57	$287.70
AnnAvg	785	500	285	0	0	$10.00	$28.10	$19.15	$0.00	$0.00	$27.56	$5.35	$90.16
ResAvg	1,150	500	500	150	0	$10.00	$28.10	$33.60	$11.97	$0.00	$40.38	$7.84	$131.89

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill		
		500	1000	>1000			500	1000	>1000						
						$15.00	$0.06401	$0.08059	$0.08059		$0.035868	$0.00000		$ Change	% Change
Small	822	500	322	0		$15.00	$32.00	$25.95	$0.00		$29.48	$0.00	$102.43	$8.22	8.7%
Medium	1,384	500	500	384		$15.00	$32.00	$40.29	$30.95		$49.64	$0.00	$167.88	$7.51	4.7%
Large	1,997	500	500	997		$15.00	$32.00	$40.29	$80.35		$71.63	$0.00	$239.27	$4.27	1.8%
XLg	2,430	500	500	1,430		$15.00	$32.00	$40.29	$115.24		$87.16	$0.00	$289.69	$1.99	0.7%
AnnAvg	785	500	285	0		$15.00	$32.00	$22.97	$0.00		$28.16	$0.00	$98.13	$7.97	8.8%
ResAvg	1,150	500	500	150		$15.00	$32.00	$40.29	$12.09		$41.25	$0.00	$140.63	$8.74	6.6%

EXHIBIT HS-8

LIFELINE RESIDENTIAL SERVICE RATE R-01LL

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	3500	>3500		500	1000	3500	>3500					
						$10.00	$0.05620	$0.06520	$0.07810	$0.08710	$0.031532	$0.00682			
Small	473	473	0	0	0	$10.00	$26.58	$0.00	$0.00	$0.00	$14.91	$3.23	$54.72	$45.72	-16.4%
Medium	740	500	240	0	0	$10.00	$28.10	$15.65	$0.00	$0.00	$23.33	$5.05	$82.13	$73.13	-11.0%
Large	1,071	500	500	71	0	$10.00	$28.10	$32.60	$5.55	$0.00	$33.77	$7.30	$117.32	$108.32	-7.7%
XLg	1,310	500	500	310	0	$10.00	$28.10	$32.60	$24.21	$0.00	$41.31	$8.93	$145.15	$136.15	-6.2%
AnnAvg	662	500	162	0	0	$10.00	$28.10	$10.55	$0.00	$0.00	$20.87	$4.51	$74.03	$65.03	-12.2%
ResAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78	$77.78	-10.4%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000			500	1000	>1000							
						$15.00	$0.06401	$0.08059	$0.08059		$0.032537	$0.00000				
Small	473	473	0	0		$15.00	$30.28	$0.00	$0.00		$15.39	$0.00	$60.67	$45.67	-$0.05	-0.1%
Medium	740	500	240	0		$15.00	$32.00	$19.34	$0.00		$24.08	$0.00	$90.42	$75.42	$2.29	3.1%
Large	1,071	500	500	71		$15.00	$32.00	$40.29	$5.72		$34.85	$0.00	$127.86	$112.86	$4.54	4.2%
XLg	1,310	500	500	310		$15.00	$32.00	$40.29	$24.98		$42.62	$0.00	$154.89	$139.89	$3.74	2.7%
AnnAvg	662	500	162	0		$15.00	$32.00	$13.04	$0.00		$21.54	$0.00	$81.58	$66.58	$1.55	2.4%
ResAvg	785	500	285	0		$15.00	$32.00	$22.97	$0.00		$25.54	$0.00	$95.51	$80.51	$2.73	3.5%

EXHIBIT HS-8

LIFELINE RESIDENTIAL SERVICE RATE R-01LL

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	3500	>3500		500	1000	3500	>3500					
						$10.00	$0.05620	$0.06720	$0.07980	$0.08820	$0.035111	$0.00682			
Small	683	500	183	0	0	$10.00	$28.10	$12.30	$0.00	$0.00	$23.98	$4.66	$79.04	$70.04	-11.4%
Medium	1,075	500	500	75	0	$10.00	$28.10	$33.60	$5.99	$0.00	$37.74	$7.33	$122.76	$113.76	-7.3%
Large	1,569	500	500	569	0	$10.00	$28.10	$33.60	$45.41	$0.00	$55.09	$10.70	$182.90	$173.90	-4.9%
XLg	1,880	500	500	880	0	$10.00	$28.10	$33.60	$70.22	$0.00	$66.01	$12.82	$220.75	$211.75	-4.1%
AnnAvg	662	500	162	0	0	$10.00	$28.10	$10.88	$0.00	$0.00	$23.24	$4.51	$76.73	$67.73	-11.7%
ResAvg	1,150	500	500	150	0	$10.00	$28.10	$33.60	$11.97	$0.00	$40.38	$7.84	$131.89	$122.89	-6.8%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000			500	1000	>1000							
						$15.00	$0.06401	$0.08059	$0.08059		$0.035868	$0.00000				
Small	683	500	183	0		$15.00	$32.00	$14.75	$0.00		$24.50	$0.00	$86.25	$71.25	$1.21	1.7%
Medium	1,075	500	500	75		$15.00	$32.00	$40.29	$6.04		$38.56	$0.00	$131.89	$116.89	$3.13	2.8%
Large	1,569	500	500	569		$15.00	$32.00	$40.29	$45.85		$56.28	$0.00	$189.42	$174.42	$0.52	0.3%
XLg	1,880	500	500	880		$15.00	$32.00	$40.29	$70.92		$67.43	$0.00	$225.64	$210.64	-$1.11	-0.5%
AnnAvg	662	500	162	0		$15.00	$32.00	$13.04	$0.00		$23.74	$0.00	$83.78	$68.78	$1.05	1.6%
ResAvg	1,150	500	500	150		$15.00	$32.00	$40.29	$12.09		$41.25	$0.00	$140.63	$125.63	$2.74	2.2%

EXHIBIT HS-8

LIFELINE SERVICE RATE R-04-01 FROZEN

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.05700	$0.05700	$0.05700	$0.025698	$0.00682			
Small	381	381	0	0	$6.90	$21.72	$0.00	$0.00	$9.79	$2.60	$41.01	$28.71	-30.0%
Medium	604	500	104	0	$6.90	$28.50	$5.93	$0.00	$15.52	$4.12	$60.97	$45.73	-25.0%
Large	913	500	413	0	$6.90	$28.50	$23.54	$0.00	$23.46	$6.23	$88.63	$66.47	-25.0%
XLg	1,197	500	500	197	$6.90	$28.50	$28.50	$11.23	$30.76	$8.16	$114.05	$96.94	-15.0%
AnnAvg	560	500	60	0	$6.90	$28.50	$3.42	$0.00	$14.39	$3.82	$57.03	$39.92	-30.0%
ResAvg	785	500	285	0	$6.90	$28.50	$16.25	$0.00	$20.17	$5.35	$77.17	$57.88	-25.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06401	$0.08059	$0.08059	$0.032537	$0.00000				
Small	381	381	0	0	$15.00	$24.39	$0.00	$0.00	$12.40	$0.00	$51.79	$20.79	-$7.92	-27.6%
Medium	604	500	104	0	$15.00	$32.00	$8.38	$0.00	$19.65	$0.00	$75.03	$44.03	-$1.70	-3.7%
Large	913	500	413	0	$15.00	$32.00	$33.28	$0.00	$29.71	$0.00	$109.99	$78.99	$12.52	18.8%
XLg	1,197	500	500	197	$15.00	$32.00	$40.29	$15.88	$38.95	$0.00	$142.12	$111.12	$14.18	14.6%
AnnAvg	560	500	60	0	$15.00	$32.00	$4.84	$0.00	$18.22	$0.00	$70.06	$39.06	-$0.86	-2.2%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$25.54	$0.00	$95.51	$64.51	$6.63	11.5%

EXHIBIT HS-8

LIFELINE SERVICE RATE R-04-01 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.06110	$0.06110	$0.06110	$0.033198	$0.00682			
Small	552	500	52	0	$6.90	$30.55	$3.18	$0.00	$18.33	$3.76	$62.72	$43.90	-30.0%
Medium	894	500	394	0	$6.90	$30.55	$24.04	$0.00	$29.66	$6.09	$97.24	$72.93	-25.0%
Large	1,280	500	500	280	$6.90	$30.55	$30.55	$17.11	$42.49	$8.73	$136.33	$115.88	-15.0%
XLg	1,550	500	500	550	$6.90	$30.55	$30.55	$33.61	$51.46	$10.57	$163.64	$163.64	0.0%
AnnAvg	560	500	60	0	$6.90	$30.55	$3.67	$0.00	$18.59	$3.82	$63.53	$44.47	-30.0%
ResAvg	1,150	500	500	150	$6.90	$30.55	$30.55	$9.17	$38.18	$7.84	$123.19	$104.71	-15.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06401	$0.08059	$0.08059	$0.035868	$0.00000				
Small	552	500	52	0	$15.00	$32.00	$4.19	$0.00	$19.80	$0.00	$70.99	$39.99	-$3.91	-8.9%
Medium	894	500	394	0	$15.00	$32.00	$31.71	$0.00	$32.05	$0.00	$110.76	$79.76	$6.83	9.4%
Large	1,280	500	500	280	$15.00	$32.00	$40.29	$22.56	$45.91	$0.00	$155.76	$124.76	$8.88	7.7%
XLg	1,550	500	500	550	$15.00	$32.00	$40.29	$44.32	$55.60	$0.00	$187.21	$156.21	-$7.43	-4.5%
AnnAvg	560	500	60	0	$15.00	$32.00	$4.84	$0.00	$20.09	$0.00	$71.93	$40.93	-$3.54	-8.0%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$41.25	$0.00	$140.63	$109.63	$4.92	4.7%

EXHIBIT HS-8

LIFELINE SERVICE RATE R-05-01 FROZEN

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.05700	$0.05700	$0.05700	$0.025698	$0.00682			
Small	480	480	0	0	$6.90	$27.36	$0.00	$0.00	$12.34	$3.27	$49.87	$39.90	-20.0%
Medium	719	500	219	0	$6.90	$28.50	$12.48	$0.00	$18.48	$4.90	$71.26	$60.57	-15.0%
Large	1,050	500	500	50	$6.90	$28.50	$28.50	$2.85	$26.98	$7.16	$100.89	$100.89	0.0%
XLg	1,314	500	500	314	$6.90	$28.50	$28.50	$17.90	$33.77	$8.96	$124.53	$124.53	0.0%
AnnAvg	659	500	159	0	$6.90	$28.50	$9.09	$0.00	$16.94	$4.50	$65.93	$56.04	-15.0%
ResAvg	785	500	285	0	$6.90	$28.50	$16.25	$0.00	$20.17	$5.35	$77.17	$65.59	-15.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06401	$0.08059	$0.08059	$0.032537	$0.00000				
Small	480	480	0	0	$15.00	$30.72	$0.00	$0.00	$15.62	$0.00	$61.34	$46.34	$6.44	16.1%
Medium	719	500	219	0	$15.00	$32.00	$17.65	$0.00	$23.39	$0.00	$88.04	$73.04	$12.47	20.6%
Large	1,050	500	500	50	$15.00	$32.00	$40.29	$4.03	$34.16	$0.00	$125.48	$110.48	$9.59	9.5%
XLg	1,314	500	500	314	$15.00	$32.00	$40.29	$25.30	$42.75	$0.00	$155.34	$140.34	$15.81	12.7%
AnnAvg	659	500	159	0	$15.00	$32.00	$12.84	$0.00	$21.45	$0.00	$81.29	$66.29	$10.25	18.3%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$25.54	$0.00	$95.51	$80.51	$14.92	22.7%

EXHIBIT HS-8

LIFELINE SERVICE RATE R-05-01 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.06110	$0.06110	$0.06110	$0.033198	$0.00682			
Small	670	500	170	0	$6.90	$30.55	$10.39	$0.00	$22.24	$4.57	$74.65	$63.45	-15.0%
Medium	1,012	500	500	12	$6.90	$30.55	$30.55	$0.70	$33.58	$6.90	$109.18	$109.18	0.0%
Large	1,460	500	500	460	$6.90	$30.55	$30.55	$28.11	$48.47	$9.96	$154.54	$154.54	0.0%
XLg	1,796	500	500	796	$6.90	$30.55	$30.55	$48.64	$59.62	$12.25	$188.51	$188.51	0.0%
AnnAvg	659	500	159	0	$6.90	$30.55	$9.74	$0.00	$21.89	$4.50	$73.58	$62.54	-15.0%
ResAvg	1,150	500	500	150	$6.90	$30.55	$30.55	$9.17	$38.18	$7.84	$123.19	$123.19	0.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06401	$0.08059	$0.08059	$0.035868	$0.00000				
Small	670	500	170	0	$15.00	$32.00	$13.70	$0.00	$24.03	$0.00	$84.73	$69.73	$6.28	9.9%
Medium	1,012	500	500	12	$15.00	$32.00	$40.29	$0.93	$36.28	$0.00	$124.50	$109.50	$0.32	0.3%
Large	1,460	500	500	460	$15.00	$32.00	$40.29	$37.07	$52.37	$0.00	$176.73	$161.73	$7.19	4.7%
XLg	1,796	500	500	796	$15.00	$32.00	$40.29	$64.15	$64.42	$0.00	$215.86	$200.86	$12.35	6.6%
AnnAvg	659	500	159	0	$15.00	$32.00	$12.84	$0.00	$23.65	$0.00	$83.49	$68.49	$5.95	9.5%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$41.25	$0.00	$140.63	$125.63	$2.44	2.0%

EXHIBIT HS-8

LIFELINE SERVICE RATE R-06-01 FROZEN

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.05700	$0.05700	$0.05700	$0.025698	$0.00682			
Small	490	490	0	0	$6.90	$27.93	$0.00	$0.00	$12.59	$3.34	$50.76	$41.76	-17.7%
Medium	769	500	269	0	$6.90	$28.50	$15.33	$0.00	$19.76	$5.24	$75.73	$66.73	-11.9%
Large	1,127	500	500	127	$6.90	$28.50	$28.50	$7.24	$28.96	$7.69	$107.79	$98.79	-8.3%
XLg	1,400	500	500	400	$6.90	$28.50	$28.50	$22.80	$35.98	$9.55	$132.23	$123.23	-6.8%
AnnAvg	730	500	230	0	$6.90	$28.50	$13.08	$0.00	$18.75	$4.98	$72.21	$63.21	-12.5%
ResAvg	785	500	285	0	$6.90	$28.50	$16.25	$0.00	$20.17	$5.35	$77.17	$68.17	-11.7%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06401	$0.08059	$0.08059	$0.032537	$0.00000				
Small	490	490	0	0	$15.00	$31.36	$0.00	$0.00	$15.94	$0.00	$62.30	$47.30	$5.54	13.3%
Medium	769	500	269	0	$15.00	$32.00	$21.68	$0.00	$25.02	$0.00	$93.70	$78.70	$11.97	17.9%
Large	1,127	500	500	127	$15.00	$32.00	$40.29	$10.23	$36.67	$0.00	$134.19	$119.19	$20.40	20.6%
XLg	1,400	500	500	400	$15.00	$32.00	$40.29	$32.24	$45.55	$0.00	$165.08	$150.08	$26.85	21.8%
AnnAvg	730	500	230	0	$15.00	$32.00	$18.50	$0.00	$23.74	$0.00	$89.24	$74.24	$11.03	17.4%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$25.54	$0.00	$95.51	$80.51	$12.34	18.1%

EXHIBIT HS-8

LIFELINE SERVICE RATE R-06-01 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.06110	$0.06110	$0.06110	$0.033198	$0.00682			
Small	758	500	258	0	$6.90	$30.55	$15.76	$0.00	$25.16	$5.17	$83.54	$74.54	-10.8%
Medium	1,220	500	500	220	$6.90	$30.55	$30.55	$13.44	$40.50	$8.32	$130.26	$121.26	-6.9%
Large	1,737	500	500	737	$6.90	$30.55	$30.55	$45.03	$57.66	$11.85	$182.54	$173.54	-4.9%
XLg	2,092	500	500	1,092	$6.90	$30.55	$30.55	$66.72	$69.45	$14.27	$218.44	$209.44	-4.1%
AnnAvg	730	500	230	0	$6.90	$30.55	$14.02	$0.00	$24.22	$4.98	$80.67	$71.67	-11.2%
ResAvg	1,150	500	500	150	$6.90	$30.55	$30.55	$9.17	$38.18	$7.84	$123.19	$114.19	-7.3%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06401	$0.08059	$0.08059	$0.035868	$0.00000				
Small	758	500	258	0	$15.00	$32.00	$20.79	$0.00	$27.19	$0.00	$94.98	$79.98	$5.44	7.3%
Medium	1,220	500	500	220	$15.00	$32.00	$40.29	$17.73	$43.76	$0.00	$148.78	$133.78	$12.52	10.3%
Large	1,737	500	500	737	$15.00	$32.00	$40.29	$59.39	$62.30	$0.00	$208.98	$193.98	$20.44	11.8%
XLg	2,092	500	500	1,092	$15.00	$32.00	$40.29	$88.00	$75.04	$0.00	$250.33	$235.33	$25.89	12.4%
AnnAvg	730	500	230	0	$15.00	$32.00	$18.50	$0.00	$26.17	$0.00	$91.67	$76.67	$5.00	7.0%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$41.25	$0.00	$140.63	$125.63	$11.44	10.0%

EXHIBIT HS-8

LIFELINE SERVICE RATE R-08-01 FROZEN

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.05700	$0.05700	$0.05700	$0.025698	$0.00682			
Small	688	500	188	0	$6.90	$28.50	$10.72	$0.00	$17.68	$4.69	$68.49	$44.52	-35.0%
Medium	1,016	500	500	16	$6.90	$28.50	$28.50	$0.91	$26.11	$6.93	$97.85	$68.50	-30.0%
Large	1,423	500	500	423	$6.90	$28.50	$28.50	$24.11	$36.57	$9.70	$134.28	$94.00	-30.0%
XLg	1,720	500	500	720	$6.90	$28.50	$28.50	$41.04	$44.20	$11.73	$160.87	$112.61	-30.0%
AnnAvg	974	500	474	0	$6.90	$28.50	$27.04	$0.00	$25.04	$6.64	$94.12	$61.18	-35.0%
ResAvg	785	500	285	0	$6.90	$28.50	$16.25	$0.00	$20.17	$5.35	$77.17	$50.16	-35.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06401	$0.08059	$0.08059	$0.032537	$0.00000				
Small	688	500	188	0	$15.00	$32.00	$15.15	$0.00	$22.39	$0.00	$84.54	$44.54	$0.02	0.0%
Medium	1,016	500	500	16	$15.00	$32.00	$40.29	$1.29	$33.06	$0.00	$121.64	$81.64	$13.14	19.2%
Large	1,423	500	500	423	$15.00	$32.00	$40.29	$34.09	$46.30	$0.00	$167.68	$127.68	$33.68	35.8%
XLg	1,720	500	500	720	$15.00	$32.00	$40.29	$58.02	$55.96	$0.00	$201.27	$161.27	$48.66	43.2%
AnnAvg	974	500	474	0	$15.00	$32.00	$38.22	$0.00	$31.70	$0.00	$116.92	$76.92	$15.74	25.7%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$25.54	$0.00	$95.51	$55.51	$5.35	10.7%

EXHIBIT HS-8

LIFELINE SERVICE RATE R-08-01 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.06110	$0.06110	$0.06110	$0.033198	$0.00682			
Small	1,090	500	500	90	$6.90	$30.55	$30.55	$5.50	$36.19	$7.43	$117.12	$81.98	-30.0%
Medium	1,614	500	500	614	$6.90	$30.55	$30.55	$37.52	$53.58	$11.01	$170.11	$119.08	-30.0%
Large	2,170	500	500	1,170	$6.90	$30.55	$30.55	$71.49	$72.04	$14.80	$226.33	$203.70	-10.0%
XLg	2,511	500	500	1,511	$6.90	$30.55	$30.55	$92.32	$83.36	$17.13	$260.81	$234.73	-10.0%
AnnAvg	974	500	474	0	$6.90	$30.55	$28.98	$0.00	$32.35	$6.64	$105.42	$68.52	-35.0%
ResAvg	1,150	500	500	150	$6.90	$30.55	$30.55	$9.17	$38.18	$7.84	$123.19	$86.23	-30.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06401	$0.08059	$0.08059	$0.035868	$0.00000				
Small	1,090	500	500	90	$15.00	$32.00	$40.29	$7.25	$39.10	$0.00	$133.64	$93.64	$11.66	14.2%
Medium	1,614	500	500	614	$15.00	$32.00	$40.29	$49.48	$57.89	$0.00	$194.66	$154.66	$35.58	29.9%
Large	2,170	500	500	1,170	$15.00	$32.00	$40.29	$94.29	$77.83	$0.00	$259.41	$219.41	$15.71	7.7%
XLg	2,511	500	500	1,511	$15.00	$32.00	$40.29	$121.77	$90.06	$0.00	$299.12	$259.12	$24.39	10.4%
AnnAvg	974	500	474	0	$15.00	$32.00	$38.22	$0.00	$34.95	$0.00	$120.17	$80.17	$11.65	17.0%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$41.25	$0.00	$140.63	$100.63	$14.40	16.7%

EXHIBIT HS-8

RESIDENTIAL SERVICE TIME OF USE RATE R-80

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill
		500	1000	>1000		500	1000	>1000			
On-Peak	0.25				$11.50	$0.05680	$0.05680	$0.05680	$0.032893	$0.00682	
Off-Peak	0.75					$0.04180	$0.04180	$0.04180	$0.027092		
Small	796	500	296	0	$11.50	$22.76	$13.48	$0.00	$22.71	$5.43	$75.88
Medium	1,196	500	500	196	$11.50	$22.76	$22.76	$8.92	$34.13	$8.16	$108.23
Large	1,678	500	500	678	$11.50	$22.76	$22.76	$30.87	$47.88	$11.44	$147.21
XLg	2,047	500	500	1,047	$11.50	$22.76	$22.76	$47.67	$58.41	$13.96	$177.06
AnnAvg	1,125	500	500	125	$11.50	$22.76	$22.76	$5.70	$32.10	$7.67	$102.49
ResAvg	785	500	285	0	$11.50	$22.76	$12.97	$0.00	$22.40	$5.35	$74.98

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill		
		500	1000	>1000		500	1000	>1000				$ Change	% Change
On-Peak	0.25				$15.00	$0.06401	$0.08059	$0.08059	$0.033893	$0.00000			
Off-Peak	0.75					$0.06401	$0.08059	$0.08059	$0.028092				
Small	796	500	296	0	$15.00	$32.00	$23.85	$0.00	$23.51	$0.00	$94.36	$18.48	24.4%
Medium	1,196	500	500	196	$15.00	$32.00	$40.29	$15.80	$35.32	$0.00	$138.41	$30.18	27.9%
Large	1,678	500	500	678	$15.00	$32.00	$40.29	$54.64	$49.56	$0.00	$191.49	$44.28	30.1%
XLg	2,047	500	500	1,047	$15.00	$32.00	$40.29	$84.38	$60.45	$0.00	$232.12	$55.06	31.1%
AnnAvg	1,125	500	500	125	$15.00	$32.00	$40.29	$10.08	$33.23	$0.00	$130.60	$28.11	27.4%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$23.18	$0.00	$93.15	$18.17	24.2%

EXHIBIT HS-8

RESIDENTIAL SERVICE TIME OF USE RATE R-80

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill
		500	1000	>1000	$11.50	500	1000	>1000			
On-Peak	0.23					$0.06680	$0.06680	$0.06680	$0.050669	$0.00682	
Off-Peak	0.77					$0.05180	$0.05180	$0.05180	$0.026679		
Small	1,249	500	500	249	$11.50	$27.61	$27.61	$13.72	$40.13	$8.51	$129.08
Medium	1,881	500	500	881	$11.50	$27.61	$27.61	$48.65	$60.46	$12.83	$188.66
Large	2,539	500	500	1,539	$11.50	$27.61	$27.61	$84.98	$81.61	$17.32	$250.63
XLg	3,011	500	500	2,011	$11.50	$27.61	$27.61	$111.04	$96.78	$20.54	$295.08
AnnAvg	1,125	500	500	125	$11.50	$27.61	$27.61	$6.91	$36.16	$7.67	$117.46
ResAvg	1,150	500	500	150	$11.50	$27.61	$27.61	$8.28	$36.96	$7.84	$119.80

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill		
		500	1000	>1000		500	1000	>1000					
On-Peak	0.23				$15.00	$0.06401	$0.08059	$0.08059	$0.051660	$0.00000			
Off-Peak	0.77					$0.06401	$0.08059	$0.08059	$0.026750			$ Change	% Change
Small	1,249	500	500	249	$15.00	$32.00	$40.29	$20.03	$40.48	$0.00	$147.80	$18.72	14.5%
Medium	1,881	500	500	881	$15.00	$32.00	$40.29	$71.00	$60.99	$0.00	$219.28	$30.62	16.2%
Large	2,539	500	500	1,539	$15.00	$32.00	$40.29	$124.02	$82.32	$0.00	$293.63	$43.00	17.2%
XLg	3,011	500	500	2,011	$15.00	$32.00	$40.29	$162.06	$97.62	$0.00	$346.97	$51.89	17.6%
AnnAvg	1,125	500	500	125	$15.00	$32.00	$40.29	$10.08	$36.48	$0.00	$133.85	$16.39	14.0%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$37.29	$0.00	$136.67	$16.87	14.1%

EXHIBIT HS-8

LIFELINE RESIDENTIAL SERVICE TIME OF USE RATE R-80L

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.25				$11.50	$0.05680	$0.05680	$0.05680	$0.032893	$0.00682			
Off-Peak	0.75					$0.04180	$0.04180	$0.04180	$0.027092				
Small	496	496	0	0	$11.50	$22.56	$0.00	$0.00	$14.14	$3.38	$51.58	$42.58	-17.4%
Medium	949	500	449	0	$11.50	$22.76	$20.44	$0.00	$27.08	$6.47	$88.25	$79.25	-10.2%
Large	1,507	500	500	507	$11.50	$22.76	$22.76	$23.08	$43.00	$10.28	$133.38	$124.38	-6.7%
XLg	1,917	500	500	917	$11.50	$22.76	$22.76	$41.75	$54.70	$13.07	$166.54	$157.54	-5.4%
AnnAvg	816	500	316	0	$11.50	$22.76	$14.37	$0.00	$23.27	$5.56	$77.46	$68.46	-11.6%
ResAvg	785	500	285	0	$11.50	$22.76	$12.97	$0.00	$22.40	$5.35	$74.98	$65.98	-12.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.25				$15.00	$0.06401	$0.08059	$0.08059	$0.033893	$0.00000				
Off-Peak	0.75					$0.06401	$0.08059	$0.08059	$0.028092				$ Change	% Change
Small	496	496	0	0	$15.00	$31.72	$0.00	$0.00	$14.63	$0.00	$61.35	$46.35	$3.77	8.9%
Medium	949	500	449	0	$15.00	$32.00	$36.18	$0.00	$28.03	$0.00	$111.21	$96.21	$16.96	21.4%
Large	1,507	500	500	507	$15.00	$32.00	$40.29	$40.86	$44.51	$0.00	$172.66	$157.66	$33.28	26.8%
XLg	1,917	500	500	917	$15.00	$32.00	$40.29	$73.90	$56.61	$0.00	$217.80	$202.80	$45.26	28.7%
AnnAvg	816	500	316	0	$15.00	$32.00	$25.44	$0.00	$24.09	$0.00	$96.53	$81.53	$13.07	19.1%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$23.18	$0.00	$93.15	$78.15	$12.17	18.4%

EXHIBIT HS-8

LIFELINE RESIDENTIAL SERVICE TIME OF USE RATE R-80L

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000	$11.50	500	1000	>1000					
On-Peak	0.23					$0.06680	$0.06680	$0.06680	$0.050669	$0.00682			
Off-Peak	0.77					$0.05180	$0.05180	$0.05180	$0.026679				
Small	754	500	254	0	$11.50	$27.61	$14.02	$0.00	$24.24	$5.14	$82.51	$73.51	-10.9%
Medium	1,293	500	500	293	$11.50	$27.61	$27.61	$16.18	$41.56	$8.82	$133.28	$124.28	-6.8%
Large	2,020	500	500	1,020	$11.50	$27.61	$27.61	$56.32	$64.93	$13.78	$201.75	$192.75	-4.5%
XLg	2,353	500	500	1,353	$11.50	$27.61	$27.61	$74.71	$75.63	$16.05	$233.11	$224.11	-3.9%
AnnAvg	816	500	316	0	$11.50	$27.61	$17.43	$0.00	$26.22	$5.56	$88.32	$79.32	-10.2%
ResAvg	1,150	500	500	150	$11.50	$27.61	$27.61	$8.28	$36.96	$7.84	$119.80	$110.80	-7.5%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000					$ Change	% Change
On-Peak	0.23				$15.00	$0.06401	$0.08059	$0.08059	$0.051660	$0.00000				
Off-Peak	0.77					$0.06401	$0.08059	$0.08059	$0.026750					
Small	754	500	254	0	$15.00	$32.00	$20.47	$0.00	$24.45	$0.00	$91.92	$76.92	$3.41	4.6%
Medium	1,293	500	500	293	$15.00	$32.00	$40.29	$23.61	$41.92	$0.00	$152.82	$137.82	$13.54	10.9%
Large	2,020	500	500	1,020	$15.00	$32.00	$40.29	$82.20	$65.49	$0.00	$234.98	$219.98	$27.23	14.1%
XLg	2,353	500	500	1,353	$15.00	$32.00	$40.29	$109.04	$76.29	$0.00	$272.62	$257.62	$33.51	15.0%
AnnAvg	816	500	316	0	$15.00	$32.00	$25.44	$0.00	$26.45	$0.00	$98.89	$83.89	$4.57	5.8%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$37.29	$0.00	$136.67	$121.67	$10.87	9.8%

EXHIBIT HS-8

LIFELINE SERVICE TIME OF USE RATE R-04-21 FROZEN

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.23				$8.86	$0.06520	$0.06520	$0.06520	$0.040698	$0.00682			
Off-Peak	0.77					$0.03300	$0.03300	$0.03300	$0.020698				
Small	717	500	217	0	$8.86	$20.23	$8.78	$0.00	$18.16	$4.89	$60.92	$45.69	-25.0%
Medium	857	500	357	0	$8.86	$20.23	$14.44	$0.00	$21.71	$5.84	$71.08	$53.31	-25.0%
Large	1,060	500	500	60	$8.86	$20.23	$20.23	$2.43	$26.85	$7.23	$85.83	$72.96	-15.0%
XLg	1,545	500	500	545	$8.86	$20.23	$20.23	$22.05	$39.14	$10.54	$121.05	$121.05	0.0%
AnnAvg	950	500	450	0	$8.86	$20.23	$18.19	$0.00	$24.05	$6.48	$77.81	$58.36	-25.0%
ResAvg	785	500	285	0	$8.86	$20.23	$11.53	$0.00	$19.89	$5.35	$65.86	$49.40	-25.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.25				$15.00	$0.06401	$0.08059	$0.08059	$0.056000	$0.00000				
Off-Peak	0.75					$0.06401	$0.08059	$0.08059	$0.028092					
Small	717	500	217	0	$15.00	$32.00	$17.49	$0.00	$25.11	$0.00	$89.60	$58.60	$12.91	28.3%
Medium	857	500	357	0	$15.00	$32.00	$28.77	$0.00	$30.02	$0.00	$105.79	$74.79	$21.48	40.3%
Large	1,060	500	500	60	$15.00	$32.00	$40.29	$4.84	$37.13	$0.00	$129.26	$98.26	$25.30	34.7%
XLg	1,545	500	500	545	$15.00	$32.00	$40.29	$43.92	$54.11	$0.00	$185.32	$154.32	$33.27	27.5%
AnnAvg	950	500	450	0	$15.00	$32.00	$36.23	$0.00	$33.26	$0.00	$116.49	$85.49	$27.13	46.5%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$27.49	$0.00	$97.46	$66.46	$17.06	34.5%

EXHIBIT HS-8

LIFELINE SERVICE TIME OF USE RATE R-04-21 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000	$8.86	500	1000	>1000					
On-Peak	0.37					$0.07880	$0.07880	$0.07880	$0.053198	$0.00682			
Off-Peak	0.63					$0.03010	$0.03010	$0.03010	$0.023198				
Small	1,178	500	500	178	$8.86	$24.17	$24.17	$8.60	$40.56	$8.03	$114.39	$97.23	-15.0%
Medium	1,990	500	500	990	$8.86	$24.17	$24.17	$47.85	$68.52	$13.57	$187.14	$187.14	0.0%
Large	2,154	500	500	1,154	$8.86	$24.17	$24.17	$55.78	$74.17	$14.69	$201.84	$201.84	0.0%
XLg	2,260	500	500	1,260	$8.86	$24.17	$24.17	$60.90	$77.82	$15.41	$211.33	$211.33	0.0%
AnnAvg	950	500	450	0	$8.86	$24.17	$21.73	$0.00	$32.70	$6.48	$93.94	$70.46	-25.0%
ResAvg	1,150	500	500	150	$8.86	$24.17	$24.17	$7.25	$39.60	$7.84	$111.89	$95.11	-15.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.23				$15.00	$0.06401	$0.08059	$0.08059	$0.051660	$0.00000				
Off-Peak	0.77					$0.06401	$0.08059	$0.08059	$0.026750					
Small	1,178	500	500	178	$15.00	$32.00	$40.29	$14.34	$38.19	$0.00	$139.82	$108.82	$11.59	11.9%
Medium	1,990	500	500	990	$15.00	$32.00	$40.29	$79.78	$64.52	$0.00	$231.59	$200.59	$13.45	7.2%
Large	2,154	500	500	1,154	$15.00	$32.00	$40.29	$93.00	$69.84	$0.00	$250.13	$219.13	$17.29	8.6%
XLg	2,260	500	500	1,260	$15.00	$32.00	$40.29	$101.54	$73.28	$0.00	$262.11	$231.11	$19.78	9.4%
AnnAvg	950	500	450	0	$15.00	$32.00	$36.23	$0.00	$30.79	$0.00	$114.02	$83.02	$12.56	17.8%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$37.29	$0.00	$136.67	$105.67	$10.56	11.1%

EXHIBIT HS-8

LIFELINE SERVICE TIME OF USE RATE R-05-21 FROZEN

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.25				$8.86	$0.06520	$0.06520	$0.06520	$0.040698	$0.00682			
Off-Peak	0.75					$0.03300	$0.03300	$0.03300	$0.020698				
Small	984	500	484	0	$8.86	$20.51	$19.84	$0.00	$25.26	$6.71	$81.18	$69.00	-15.0%
Medium	1,203	500	500	203	$8.86	$20.51	$20.51	$8.33	$30.90	$8.20	$97.31	$97.31	0.0%
Large	1,447	500	500	447	$8.86	$20.51	$20.51	$18.34	$37.17	$9.87	$115.26	$115.26	0.0%
XLg	1,690	500	500	690	$8.86	$20.51	$20.51	$28.31	$43.41	$11.53	$133.13	$133.13	0.0%
AnnAvg	1,145	500	500	145	$8.86	$20.51	$20.51	$5.93	$29.40	$7.81	$93.02	$93.02	0.0%
ResAvg	785	500	285	0	$8.86	$20.51	$11.69	$0.00	$20.16	$5.35	$66.57	$56.58	-15.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000					$ Change	% Change
On-Peak	0.25				$15.00	$0.06401	$0.08059	$0.08059	$0.056000	$0.00000				
Off-Peak	0.75					$0.06401	$0.08059	$0.08059	$0.028092					
Small	984	500	484	0	$15.00	$32.00	$38.96	$0.00	$34.45	$0.00	$120.41	$105.41	$36.41	52.8%
Medium	1,203	500	500	203	$15.00	$32.00	$40.29	$16.36	$42.13	$0.00	$145.78	$130.78	$33.47	34.4%
Large	1,447	500	500	447	$15.00	$32.00	$40.29	$36.02	$50.68	$0.00	$173.99	$158.99	$43.73	37.9%
XLg	1,690	500	500	690	$15.00	$32.00	$40.29	$55.61	$59.19	$0.00	$202.09	$187.09	$53.96	40.5%
AnnAvg	1,145	500	500	145	$15.00	$32.00	$40.29	$11.64	$40.08	$0.00	$139.01	$124.01	$30.99	33.3%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$27.49	$0.00	$97.46	$82.46	$25.88	45.7%

EXHIBIT HS-8

LIFELINE SERVICE TIME OF USE RATE R-05-21 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000	$8.86	500	1000	>1000					
On-Peak	0.38					$0.07880	$0.07880	$0.07880	$0.053198	$0.00682			
Off-Peak	0.62					$0.03010	$0.03010	$0.03010	$0.023198				
Small	1,376	500	500	376	$8.86	$24.24	$24.24	$18.23	$47.50	$9.38	$132.45	$132.45	0.0%
Medium	1,897	500	500	897	$8.86	$24.24	$24.24	$43.49	$65.49	$12.94	$179.26	$179.26	0.0%
Large	2,029	500	500	1,029	$8.86	$24.24	$24.24	$49.89	$70.04	$13.84	$191.11	$191.11	0.0%
XLg	2,029	500	500	1,029	$8.86	$24.24	$24.24	$49.89	$70.04	$13.84	$191.11	$191.11	0.0%
AnnAvg	1,145	500	500	145	$8.86	$24.24	$24.24	$7.01	$39.51	$7.81	$111.67	$111.67	0.0%
ResAvg	1,150	500	500	150	$8.86	$24.24	$24.24	$7.27	$39.70	$7.84	$112.15	$112.15	0.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.23				$15.00	$0.06401	$0.08059	$0.08059	$0.051660	$0.00000				
Off-Peak	0.77					$0.06401	$0.08059	$0.08059	$0.026750					
Small	1,376	500	500	376	$15.00	$32.00	$40.29	$30.30	$44.61	$0.00	$162.20	$147.20	$14.75	11.1%
Medium	1,897	500	500	897	$15.00	$32.00	$40.29	$72.29	$61.51	$0.00	$221.09	$206.09	$26.83	15.0%
Large	2,029	500	500	1,029	$15.00	$32.00	$40.29	$82.92	$65.79	$0.00	$236.00	$221.00	$29.89	15.6%
XLg	2,029	500	500	1,029	$15.00	$32.00	$40.29	$82.92	$65.79	$0.00	$236.00	$221.00	$29.89	15.6%
AnnAvg	1,145	500	500	145	$15.00	$32.00	$40.29	$11.64	$37.11	$0.00	$136.04	$121.04	$9.37	8.4%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$37.29	$0.00	$136.67	$121.67	$9.52	8.5%

EXHIBIT HS-8

LIFELINE SERVICE TIME OF USE RATE R-06-21 FROZEN

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.25				$8.86	$0.06520	$0.06520	$0.06520	$0.040698	$0.00682			
Off-Peak	0.75					$0.03300	$0.03300	$0.03300	$0.020698				
Small	811	500	311	0	$8.86	$20.51	$12.76	$0.00	$20.82	$5.53	$68.48	$59.48	-13.1%
Medium	1,159	500	500	159	$8.86	$20.51	$20.51	$6.52	$29.76	$7.90	$94.06	$85.06	-9.6%
Large	1,610	500	500	610	$8.86	$20.51	$20.51	$25.02	$41.34	$10.98	$127.22	$118.22	-7.1%
XLg	2,299	500	500	1,299	$8.86	$20.51	$20.51	$53.28	$59.03	$15.68	$177.87	$168.87	-5.1%
AnnAvg	1,151	500	500	151	$8.86	$20.51	$20.51	$6.21	$29.56	$7.85	$93.50	$84.50	-9.6%
ResAvg	785	500	285	0	$8.86	$20.51	$11.69	$0.00	$20.16	$5.35	$66.57	$57.57	-13.5%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000					$ Change	% Change
On-Peak	0.25				$15.00	$0.06401	$0.08059	$0.08059	$0.056000	$0.00000				
Off-Peak	0.75					$0.06401	$0.08059	$0.08059	$0.028092					
Small	811	500	311	0	$15.00	$32.00	$25.06	$0.00	$28.40	$0.00	$100.46	$69.46	$9.98	16.8%
Medium	1,159	500	500	159	$15.00	$32.00	$40.29	$12.81	$40.59	$0.00	$140.69	$109.69	$24.63	29.0%
Large	1,610	500	500	610	$15.00	$32.00	$40.29	$49.16	$56.39	$0.00	$192.84	$161.84	$43.62	36.9%
XLg	2,299	500	500	1,299	$15.00	$32.00	$40.29	$104.68	$80.52	$0.00	$272.49	$241.49	$72.62	43.0%
AnnAvg	1,151	500	500	151	$15.00	$32.00	$40.29	$12.19	$40.32	$0.00	$139.80	$108.80	$24.30	28.8%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$27.49	$0.00	$97.46	$66.46	$8.89	15.4%

EXHIBIT HS-8

LIFELINE SERVICE TIME OF USE RATE R-06-21 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000	$8.86	500	1000	>1000					
On-Peak	0.34					$0.07880	$0.07880	$0.07880	$0.053198	$0.00682			
Off-Peak	0.66					$0.03010	$0.03010	$0.03010	$0.023198				
Small	1,065	500	500	65	$8.86	$23.29	$23.29	$3.03	$35.52	$7.26	$101.25	$92.25	-8.9%
Medium	1,606	500	500	606	$8.86	$23.29	$23.29	$28.23	$53.56	$10.95	$148.18	$139.18	-6.1%
Large	2,060	500	500	1,060	$8.86	$23.29	$23.29	$49.38	$68.70	$14.05	$187.57	$178.57	-4.8%
XLg	2,900	500	500	1,900	$8.86	$23.29	$23.29	$88.50	$96.72	$19.78	$260.44	$251.44	-3.5%
AnnAvg	1,151	500	500	151	$8.86	$23.29	$23.29	$7.05	$38.40	$7.85	$108.74	$99.74	-8.3%
ResAvg	1,150	500	500	150	$8.86	$23.29	$23.29	$6.99	$38.35	$7.84	$108.62	$99.62	-8.3%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000					$ Change	% Change
On-Peak	0.23				$15.00	$0.06401	$0.08059	$0.08059	$0.051660	$0.00000				
Off-Peak	0.77					$0.06401	$0.08059	$0.08059	$0.026750					
Small	1,065	500	500	65	$15.00	$32.00	$40.29	$5.24	$34.53	$0.00	$127.06	$96.06	$3.81	4.1%
Medium	1,606	500	500	606	$15.00	$32.00	$40.29	$48.84	$52.07	$0.00	$188.20	$157.20	$18.02	12.9%
Large	2,060	500	500	1,060	$15.00	$32.00	$40.29	$85.42	$66.79	$0.00	$239.50	$208.50	$29.93	16.8%
XLg	2,900	500	500	1,900	$15.00	$32.00	$40.29	$153.12	$94.03	$0.00	$334.44	$303.44	$52.00	20.7%
AnnAvg	1,151	500	500	151	$15.00	$32.00	$40.29	$12.19	$37.33	$0.00	$136.81	$105.81	$6.07	6.1%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$37.29	$0.00	$136.67	$105.67	$6.05	6.1%

EXHIBIT HS-8

LIFELINE SERVICE TIME OF USE RATE R-08-21 FROZEN

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.25				$8.86	$0.06520	$0.06520	$0.06520	$0.040698	$0.00682			
Off-Peak	0.75					$0.03300	$0.03300	$0.03300	$0.020698				
Small	1,070	500	500	70	$8.86	$20.45	$20.45	$2.86	$27.39	$7.30	$87.31	$61.12	-30.0%
Medium	1,285	500	500	285	$8.86	$20.45	$20.45	$11.66	$32.90	$8.76	$103.08	$72.16	-30.0%
Large	1,891	500	500	891	$8.86	$20.45	$20.45	$36.44	$48.41	$12.90	$147.51	$103.26	-30.0%
XLg	2,480	500	500	1,480	$8.86	$20.45	$20.45	$60.53	$63.49	$16.91	$190.69	$171.62	-10.0%
AnnAvg	1,485	500	500	485	$8.86	$20.45	$20.45	$19.85	$38.03	$10.13	$117.77	$82.44	-30.0%
ResAvg	785	500	285	0	$8.86	$20.45	$11.66	$0.00	$20.10	$5.35	$66.42	$43.17	-35.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000					$ Change	% Change
On-Peak	0.25				$15.00	$0.06401	$0.08059	$0.08059	$0.056000	$0.00000				
Off-Peak	0.75					$0.06401	$0.08059	$0.08059	$0.028092					
Small	1,070	500	500	70	$15.00	$32.00	$40.29	$5.64	$37.48	$0.00	$130.41	$90.41	$29.29	47.9%
Medium	1,285	500	500	285	$15.00	$32.00	$40.29	$22.97	$45.01	$0.00	$155.27	$115.27	$43.11	59.7%
Large	1,891	500	500	891	$15.00	$32.00	$40.29	$71.80	$66.23	$0.00	$225.32	$185.32	$82.06	79.5%
XLg	2,480	500	500	1,480	$15.00	$32.00	$40.29	$119.27	$86.86	$0.00	$293.42	$253.42	$81.80	47.7%
AnnAvg	1,485	500	500	485	$15.00	$32.00	$40.29	$39.11	$52.02	$0.00	$178.42	$138.42	$55.98	67.9%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$27.49	$0.00	$97.46	$57.46	$14.29	33.1%

EXHIBIT HS-8

LIFELINE SERVICE TIME OF USE RATE R-08-21 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000	$8.86	500	1000	>1000					
On-Peak	0.36					$0.07880	$0.07880	$0.07880	$0.053198	$0.00682			
Off-Peak	0.64					$0.03010	$0.03010	$0.03010	$0.023198				
Small	1,430	500	500	430	$8.86	$23.85	$23.85	$20.51	$48.67	$9.75	$135.49	$94.84	-30.0%
Medium	2,071	500	500	1,071	$8.86	$23.85	$23.85	$51.08	$70.49	$14.12	$192.25	$173.03	-10.0%
Large	3,995	500	500	2,995	$8.86	$23.85	$23.85	$142.84	$135.97	$27.25	$362.62	$326.36	-10.0%
XLg	4,939	500	500	3,939	$8.86	$23.85	$23.85	$187.86	$168.10	$33.68	$446.20	$401.58	-10.0%
AnnAvg	1,485	500	500	485	$8.86	$23.85	$23.85	$23.14	$50.55	$10.13	$140.38	$98.27	-30.0%
ResAvg	1,150	500	500	150	$8.86	$23.85	$23.85	$7.15	$39.14	$7.84	$110.69	$77.48	-30.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.23				$15.00	$0.06401	$0.08059	$0.08059	$0.051660	$0.00000				
Off-Peak	0.77					$0.06401	$0.08059	$0.08059	$0.026750				$ Change	% Change
Small	1,430	500	500	430	$15.00	$32.00	$40.29	$34.65	$46.36	$0.00	$168.30	$128.30	$33.46	35.3%
Medium	2,071	500	500	1,071	$15.00	$32.00	$40.29	$86.31	$67.15	$0.00	$240.75	$200.75	$27.72	16.0%
Large	3,995	500	500	2,995	$15.00	$32.00	$40.29	$241.36	$129.53	$0.00	$458.18	$418.18	$91.82	28.1%
XLg	4,939	500	500	3,939	$15.00	$32.00	$40.29	$317.44	$160.14	$0.00	$564.87	$524.87	$123.29	30.7%
AnnAvg	1,485	500	500	485	$15.00	$32.00	$40.29	$39.11	$48.16	$0.00	$174.56	$134.56	$36.29	36.9%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$37.29	$0.00	$136.67	$96.67	$19.19	24.8%

EXHIBIT HS-8

LIFELINE SERVICE TIME OF USE RATE R-04-70 FROZEN

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.23				$8.78	$0.09250	$0.09250	$0.09250	$0.040698	$0.00682			
Shoulder-Peak	n/a												
Off-Peak	0.77					$0.02490	$0.02490	$0.02490	$0.020698				
Small	538	500	38	0	$8.78	$20.12	$1.51	$0.00	$13.57	$3.67	$47.65	$33.36	-30.0%
Medium	850	500	350	0	$8.78	$20.12	$14.09	$0.00	$21.45	$5.80	$70.24	$52.68	-25.0%
Large	1,402	500	500	402	$8.78	$20.12	$20.12	$16.18	$35.38	$9.56	$110.14	$93.62	-15.0%
XLg	1,734	500	500	734	$8.78	$20.12	$20.12	$29.54	$43.76	$11.83	$134.15	$134.15	0.0%
AnnAvg	831	500	331	0	$8.78	$20.12	$13.34	$0.00	$20.98	$5.67	$68.89	$51.67	-25.0%
ResAvg	785	500	285	0	$8.78	$20.12	$11.47	$0.00	$19.81	$5.35	$65.53	$49.15	-25.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.25				$15.00	$0.06401	$0.08059	$0.08059	$0.056000	$0.00000				
Off-Peak	0.75					$0.06401	$0.08059	$0.08059	$0.028092				$ Change	% Change
Small	538	500	38	0	$15.00	$32.00	$3.02	$0.00	$18.83	$0.00	$68.85	$37.85	$4.49	13.5%
Medium	850	500	350	0	$15.00	$32.00	$28.21	$0.00	$29.77	$0.00	$104.98	$73.98	$21.30	40.4%
Large	1,402	500	500	402	$15.00	$32.00	$40.29	$32.40	$49.10	$0.00	$168.79	$137.79	$44.17	47.2%
XLg	1,734	500	500	734	$15.00	$32.00	$40.29	$59.15	$60.73	$0.00	$207.17	$176.17	$42.02	31.3%
AnnAvg	831	500	331	0	$15.00	$32.00	$26.71	$0.00	$29.12	$0.00	$102.83	$71.83	$20.16	39.0%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$27.49	$0.00	$97.46	$66.46	$17.31	35.2%

EXHIBIT HS-8

LIFELINE SERVICE TIME OF USE RATE R-04-70 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.22				$8.78	$0.13930	$0.13930	$0.13930	$0.055698	$0.00682			
Shoulder-Peak	0.07					$0.07400	$0.07400	$0.07400	$0.048198				
Off-Peak	0.71					$0.03790	$0.03790	$0.03790	$0.023198				
Small	866	500	366	0	$8.78	$31.40	$22.95	$0.00	$27.85	$5.90	$96.88	$72.66	-25.0%
Medium	1,170	500	500	170	$8.78	$31.40	$31.40	$10.68	$37.64	$7.98	$127.88	$108.70	-15.0%
Large	1,910	500	500	910	$8.78	$31.40	$31.40	$57.15	$61.45	$13.03	$203.21	$203.21	0.0%
XLg	2,469	500	500	1,469	$8.78	$31.40	$31.40	$92.25	$79.43	$16.84	$260.10	$260.10	0.0%
AnnAvg	831	500	331	0	$8.78	$31.40	$20.81	$0.00	$26.75	$5.67	$93.41	$70.06	-25.0%
ResAvg	1,150	500	500	150	$8.78	$31.40	$31.40	$9.42	$37.00	$7.84	$125.84	$106.96	-15.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.23				$15.00	$0.06401	$0.08059	$0.08059	$0.051660	$0.00000				
Off-Peak	0.77					$0.06401	$0.08059	$0.08059	$0.026750				$ Change	% Change
Small	866	500	366	0	$15.00	$32.00	$29.45	$0.00	$28.06	$0.00	$104.51	$73.51	$0.85	1.2%
Medium	1,170	500	500	170	$15.00	$32.00	$40.29	$13.70	$37.93	$0.00	$138.92	$107.92	-$0.78	-0.7%
Large	1,910	500	500	910	$15.00	$32.00	$40.29	$73.33	$61.93	$0.00	$222.55	$191.55	-$11.66	-5.7%
XLg	2,469	500	500	1,469	$15.00	$32.00	$40.29	$118.38	$80.05	$0.00	$285.72	$254.72	-$5.38	-2.1%
AnnAvg	831	500	331	0	$15.00	$32.00	$26.71	$0.00	$26.96	$0.00	$100.67	$69.67	-$0.39	-0.6%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$37.29	$0.00	$136.67	$105.67	-$1.29	-1.2%

EXHIBIT HS-8

LIFELINE SERVICE TIME OF USE RATE R-05-70 FROZEN

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.20				$8.78	$0.09250	$0.09250	$0.09250	$0.040698	$0.00682			
Shoulder-Peak	n/a												
Off-Peak	0.80					$0.02490	$0.02490	$0.02490	$0.020698				
Small	428	428	0	0	$8.78	$16.49	$0.00	$0.00	$10.58	$2.92	$38.77	$31.02	-20.0%
Medium	776	500	276	0	$8.78	$19.26	$10.63	$0.00	$19.19	$5.29	$63.15	$53.68	-15.0%
Large	1,220	500	500	220	$8.78	$19.26	$19.26	$8.48	$30.17	$8.32	$94.27	$94.27	0.0%
XLg	1,267	500	500	267	$8.78	$19.26	$19.26	$10.29	$31.33	$8.64	$97.56	$97.56	0.0%
AnnAvg	684	500	184	0	$8.78	$19.26	$7.09	$0.00	$16.91	$4.66	$56.70	$48.20	-15.0%
ResAvg	785	500	285	0	$8.78	$19.26	$10.98	$0.00	$19.41	$5.35	$63.78	$54.21	-15.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.25				$15.00	$0.06401	$0.08059	$0.08059	$0.056000	$0.00000				
Off-Peak	0.75					$0.06401	$0.08059	$0.08059	$0.028092				$ Change	% Change
Small	428	428	0	0	$15.00	$27.40	$0.00	$0.00	$14.99	$0.00	$57.39	$42.39	$11.37	36.7%
Medium	776	500	276	0	$15.00	$32.00	$22.24	$0.00	$27.18	$0.00	$96.42	$81.42	$27.74	51.7%
Large	1,220	500	500	220	$15.00	$32.00	$40.29	$17.73	$42.73	$0.00	$147.75	$132.75	$38.48	40.8%
XLg	1,267	500	500	267	$15.00	$32.00	$40.29	$21.52	$44.38	$0.00	$153.19	$138.19	$40.63	41.6%
AnnAvg	684	500	184	0	$15.00	$32.00	$14.82	$0.00	$23.95	$0.00	$85.77	$70.77	$22.57	46.8%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$27.49	$0.00	$97.46	$82.46	$28.25	52.1%

EXHIBIT HS-8

LIFELINE SERVICE TIME OF USE RATE R-05-70 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.20				$8.78	$0.13930	$0.13930	$0.13930	$0.055698	$0.00682			
Shoulder-Peak	0.08					$0.07400	$0.07400	$0.07400	$0.048198				
Off-Peak	0.72					$0.03790	$0.03790	$0.03790	$0.023198				
Small	752	500	252	0	$8.78	$30.66	$15.42	$0.00	$23.88	$5.13	$83.87	$71.29	-15.0%
Medium	1,203	500	500	203	$8.78	$30.66	$30.66	$12.42	$38.22	$8.20	$128.94	$128.94	0.0%
Large	1,647	500	500	647	$8.78	$30.66	$30.66	$39.68	$52.35	$11.23	$173.36	$173.36	0.0%
XLg	1,935	500	500	935	$8.78	$30.66	$30.66	$57.34	$61.50	$13.20	$202.14	$202.14	0.0%
AnnAvg	684	500	184	0	$8.78	$30.66	$11.28	$0.00	$21.74	$4.66	$77.12	$65.55	-15.0%
ResAvg	1,150	500	500	150	$8.78	$30.66	$30.66	$9.20	$36.55	$7.84	$123.69	$123.69	0.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.23				$15.00	$0.06401	$0.08059	$0.08059	$0.051660	$0.00000				
Off-Peak	0.77					$0.06401	$0.08059	$0.08059	$0.026750					
Small	752	500	252	0	$15.00	$32.00	$20.27	$0.00	$24.37	$0.00	$91.64	$76.64	$5.35	7.5%
Medium	1,203	500	500	203	$15.00	$32.00	$40.29	$16.32	$38.99	$0.00	$142.60	$127.60	-$1.34	-1.0%
Large	1,647	500	500	647	$15.00	$32.00	$40.29	$52.14	$53.40	$0.00	$192.83	$177.83	$4.47	2.6%
XLg	1,935	500	500	935	$15.00	$32.00	$40.29	$75.35	$62.74	$0.00	$225.38	$210.38	$8.24	4.1%
AnnAvg	684	500	184	0	$15.00	$32.00	$14.82	$0.00	$22.17	$0.00	$83.99	$68.99	$3.44	5.2%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$37.29	$0.00	$136.67	$121.67	-$2.02	-1.6%

EXHIBIT HS-8

LIFELINE SERVICE TIME OF USE RATE R-06-70 FROZEN

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.23				$8.78	$0.09250	$0.09250	$0.09250	$0.040698	$0.00682			
Shoulder-Peak	n/a												
Off-Peak	0.77					$0.02490	$0.02490	$0.02490	$0.020698				
Small	664	500	164	0	$8.78	$20.14	$6.60	$0.00	$16.76	$4.53	$56.81	$47.81	-15.8%
Medium	1,011	500	500	11	$8.78	$20.14	$20.14	$0.44	$25.52	$6.90	$81.92	$72.92	-11.0%
Large	1,395	500	500	395	$8.78	$20.14	$20.14	$15.91	$35.22	$9.51	$109.70	$100.70	-8.2%
XLg	1,744	500	500	744	$8.78	$20.14	$20.14	$29.96	$44.03	$11.89	$134.94	$125.94	-6.7%
AnnAvg	933	500	433	0	$8.78	$20.14	$17.43	$0.00	$23.55	$6.36	$76.26	$67.26	-11.8%
ResAvg	785	500	285	0	$8.78	$20.14	$11.48	$0.00	$19.82	$5.35	$65.57	$56.57	-13.7%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.25				$15.00	$0.06401	$0.08059	$0.08059	$0.056000	$0.00000				
Off-Peak	0.75					$0.06401	$0.08059	$0.08059	$0.028092				$ Change	% Change
Small	664	500	164	0	$15.00	$32.00	$13.22	$0.00	$23.26	$0.00	$83.48	$68.48	$20.67	43.2%
Medium	1,011	500	500	11	$15.00	$32.00	$40.29	$0.89	$35.41	$0.00	$123.59	$108.59	$35.67	48.9%
Large	1,395	500	500	395	$15.00	$32.00	$40.29	$31.83	$48.86	$0.00	$167.98	$152.98	$52.28	51.9%
XLg	1,744	500	500	744	$15.00	$32.00	$40.29	$59.96	$61.08	$0.00	$208.33	$193.33	$67.39	53.5%
AnnAvg	933	500	433	0	$15.00	$32.00	$34.88	$0.00	$32.67	$0.00	$114.55	$99.55	$32.29	48.0%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$27.49	$0.00	$97.46	$82.46	$25.89	45.8%

EXHIBIT HS-8

LIFELINE SERVICE TIME OF USE RATE R-06-70 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.20				$8.78	$0.13930	$0.13930	$0.13930	$0.055698	$0.00682			
Shoulder-Peak	0.09					$0.07400	$0.07400	$0.07400	$0.048198				
Off-Peak	0.71					$0.03790	$0.03790	$0.03790	$0.023198				
Small	971	500	471	0	$8.78	$30.93	$29.10	$0.00	$31.12	$6.62	$106.55	$97.55	-8.4%
Medium	1,577	500	500	577	$8.78	$30.93	$30.93	$35.69	$50.57	$10.76	$167.66	$158.66	-5.4%
Large	2,196	500	500	1,196	$8.78	$30.93	$30.93	$73.97	$70.42	$14.98	$230.01	$221.01	-3.9%
XLg	2,503	500	500	1,503	$8.78	$30.93	$30.93	$92.96	$80.27	$17.07	$260.94	$251.94	-3.4%
AnnAvg	933	500	433	0	$8.78	$30.93	$26.77	$0.00	$29.92	$6.36	$102.76	$93.76	-8.8%
ResAvg	1,150	500	500	150	$8.78	$30.93	$30.93	$9.28	$36.88	$7.84	$124.64	$115.64	-7.2%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000					$ Change	% Change
On-Peak	0.23				$15.00	$0.06401	$0.08059	$0.08059	$0.051660	$0.00000				
Off-Peak	0.77					$0.06401	$0.08059	$0.08059	$0.026750					
Small	971	500	471	0	$15.00	$32.00	$37.92	$0.00	$31.47	$0.00	$116.39	$101.39	$3.84	3.9%
Medium	1,577	500	500	577	$15.00	$32.00	$40.29	$46.50	$51.13	$0.00	$184.92	$169.92	$11.26	7.1%
Large	2,196	500	500	1,196	$15.00	$32.00	$40.29	$96.38	$71.20	$0.00	$254.87	$239.87	$18.86	8.5%
XLg	2,503	500	500	1,503	$15.00	$32.00	$40.29	$121.12	$81.15	$0.00	$289.56	$274.56	$22.62	9.0%
AnnAvg	933	500	433	0	$15.00	$32.00	$34.88	$0.00	$30.24	$0.00	$112.12	$97.12	$3.36	3.6%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$37.29	$0.00	$136.67	$121.67	$6.03	5.2%

EXHIBIT HS-8

LIFELINE SERVICE TIME OF USE RATE R-08-70 FROZEN

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.22				$8.78	$0.09250	$0.09250	$0.09250	$0.040698	$0.00682			
Shoulder-Peak	n/a												
Off-Peak	0.78					$0.02490	$0.02490	$0.02490	$0.020698				
Small	770	500	270	0	$8.78	$19.74	$10.66	$0.00	$19.26	$5.25	$63.69	$41.40	-35.0%
Medium	980	500	480	0	$8.78	$19.74	$18.95	$0.00	$24.51	$6.68	$78.66	$51.13	-35.0%
Large	1,312	500	500	312	$8.78	$19.74	$19.74	$12.32	$32.81	$8.95	$102.34	$71.64	-30.0%
XLg	1,636	500	500	636	$8.78	$19.74	$19.74	$25.11	$40.92	$11.16	$125.45	$87.82	-30.0%
AnnAvg	994	500	494	0	$8.78	$19.74	$19.49	$0.00	$24.85	$6.78	$79.64	$51.77	-35.0%
ResAvg	785	500	285	0	$8.78	$19.74	$11.25	$0.00	$19.63	$5.35	$64.75	$42.09	-35.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.25				$15.00	$0.06401	$0.08059	$0.08059	$0.056000	$0.00000				
Off-Peak	0.75					$0.06401	$0.08059	$0.08059	$0.028092					
Small	770	500	270	0	$15.00	$32.00	$21.76	$0.00	$26.97	$0.00	$95.73	$64.73	$23.33	56.4%
Medium	980	500	480	0	$15.00	$32.00	$38.68	$0.00	$34.32	$0.00	$120.00	$89.00	$37.87	74.1%
Large	1,312	500	500	312	$15.00	$32.00	$40.29	$25.14	$45.95	$0.00	$158.38	$127.38	$55.74	77.8%
XLg	1,636	500	500	636	$15.00	$32.00	$40.29	$51.25	$57.30	$0.00	$195.84	$164.84	$77.02	87.7%
AnnAvg	994	500	494	0	$15.00	$32.00	$39.79	$0.00	$34.80	$0.00	$121.59	$90.59	$38.82	75.0%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$27.49	$0.00	$97.46	$66.46	$24.37	57.9%

EXHIBIT HS-8

LIFELINE SERVICE TIME OF USE RATE R-08-70 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.20				$8.78	$0.13930	$0.13930	$0.13930	$0.055698	$0.00682			
Shoulder-Peak	0.08					$0.07400	$0.07400	$0.07400	$0.048198				
Off-Peak	0.72					$0.03790	$0.03790	$0.03790	$0.023198				
Small	1,206	500	500	206	$8.78	$30.44	$30.44	$12.51	$38.18	$8.22	$128.57	$90.00	-30.0%
Medium	1,820	500	500	820	$8.78	$30.44	$30.44	$49.93	$57.65	$12.41	$189.65	$132.76	-30.0%
Large	2,139	500	500	1,139	$8.78	$30.44	$30.44	$69.35	$67.75	$14.59	$221.35	$199.22	-10.0%
XLg	2,382	500	500	1,382	$8.78	$30.44	$30.44	$84.14	$75.45	$16.25	$245.50	$220.95	-10.0%
AnnAvg	994	500	494	0	$8.78	$30.44	$30.06	$0.00	$31.48	$6.78	$107.54	$69.90	-35.0%
ResAvg	1,150	500	500	150	$8.78	$30.44	$30.44	$9.13	$36.43	$7.84	$123.06	$86.14	-30.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.23				$15.00	$0.06401	$0.08059	$0.08059	$0.051660	$0.00000				
Off-Peak	0.77					$0.06401	$0.08059	$0.08059	$0.026750				$ Change	% Change
Small	1,206	500	500	206	$15.00	$32.00	$40.29	$16.56	$39.09	$0.00	$142.94	$111.94	$21.94	24.4%
Medium	1,820	500	500	820	$15.00	$32.00	$40.29	$66.08	$59.01	$0.00	$212.38	$181.38	$48.62	36.6%
Large	2,139	500	500	1,139	$15.00	$32.00	$40.29	$91.79	$69.35	$0.00	$248.43	$217.43	$18.21	9.1%
XLg	2,382	500	500	1,382	$15.00	$32.00	$40.29	$111.37	$77.23	$0.00	$275.89	$244.89	$23.94	10.8%
AnnAvg	994	500	494	0	$15.00	$32.00	$39.79	$0.00	$32.22	$0.00	$119.01	$88.01	$18.11	25.9%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$37.29	$0.00	$136.67	$105.67	$19.53	22.7%

EXHIBIT HS-8

RESIDENTIAL SERVICE TIME OF USE SUPER-PEAK RATE R-8

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill
		500	1000	>1000		500	1000	>1000			
On-Peak	0.11				$11.50	$0.08910	$0.08910	$0.11210	$0.040200	$0.00682	
Off-Peak	0.89					$0.03850	$0.03850	$0.06150	$0.020500		
Small	557	500	57	0	$11.50	$22.05	$2.51	$0.00	$12.63	$3.80	$52.49
Medium	876	500	376	0	$11.50	$22.05	$16.56	$0.00	$19.85	$5.97	$75.93
Large	1,370	500	500	370	$11.50	$22.05	$22.05	$24.82	$31.07	$9.34	$120.83
XLg	1,715	500	500	715	$11.50	$22.05	$22.05	$47.97	$38.89	$11.70	$154.16
AnnAvg	769	500	269	0	$11.50	$22.05	$11.86	$0.00	$17.44	$5.24	$68.09
ResAvg	785	500	285	0	$11.50	$22.05	$12.57	$0.00	$17.80	$5.35	$69.27

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	$ Change	% Change
		500	1000	>1000		500	1000	>1000					
On-Peak	0.11				$15.00	$0.06401	$0.08059	$0.08059	$0.041293	$0.00000			
Off-Peak	0.89					$0.06401	$0.08059	$0.08059	$0.021492			$ Change	% Change
Small	557	500	57	0	$15.00	$32.00	$4.59	$0.00	$13.19	$0.00	$64.78	$12.29	23.4%
Medium	876	500	376	0	$15.00	$32.00	$30.26	$0.00	$20.73	$0.00	$97.99	$22.06	29.1%
Large	1,370	500	500	370	$15.00	$32.00	$40.29	$29.82	$32.44	$0.00	$149.55	$28.72	23.8%
XLg	1,715	500	500	715	$15.00	$32.00	$40.29	$57.62	$40.61	$0.00	$185.52	$31.36	20.3%
AnnAvg	769	500	269	0	$15.00	$32.00	$21.67	$0.00	$18.21	$0.00	$86.88	$18.79	27.6%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$18.59	$0.00	$88.56	$19.29	27.8%

EXHIBIT HS-8

RESIDENTIAL SERVICE TIME OF USE SUPER-PEAK RATE R-8

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill
		500	1000	>1000	$11.50	500	1000	>1000			
On-Peak	0.13					$0.09710	$0.09710	$0.12010	$0.080100	$0.00682	
Off-Peak	0.87					$0.04850	$0.04850	$0.07150	$0.022200		
Small	728	500	228	0	$11.50	$27.39	$12.46	$0.00	$21.59	$4.96	$77.90
Medium	1,222	500	500	222	$11.50	$27.39	$27.39	$17.27	$36.26	$8.33	$128.14
Large	1,666	500	500	666	$11.50	$27.39	$27.39	$51.80	$49.44	$11.36	$178.88
XLg	2,219	500	500	1,219	$11.50	$27.39	$27.39	$94.81	$65.85	$15.13	$242.07
AnnAvg	769	500	269	0	$11.50	$27.39	$14.73	$0.00	$22.82	$5.24	$81.68
ResAvg	1,150	500	500	150	$11.50	$27.39	$27.39	$11.67	$34.13	$7.84	$119.92

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	$ Change	% Change
		500	1000	>1000		500	1000	>1000					
On-Peak	0.13				$15.00	$0.06401	$0.08059	$0.08059	$0.081060	$0.00000			
Off-Peak	0.87					$0.06401	$0.08059	$0.08059	$0.022750			$ Change	% Change
Small	728	500	228	0	$15.00	$32.00	$18.33	$0.00	$22.03	$0.00	$87.36	$9.46	12.1%
Medium	1,222	500	500	222	$15.00	$32.00	$40.29	$17.89	$37.00	$0.00	$142.18	$14.04	11.0%
Large	1,666	500	500	666	$15.00	$32.00	$40.29	$53.67	$50.44	$0.00	$191.40	$12.52	7.0%
XLg	2,219	500	500	1,219	$15.00	$32.00	$40.29	$98.24	$67.19	$0.00	$252.72	$10.65	4.4%
AnnAvg	769	500	269	0	$15.00	$32.00	$21.67	$0.00	$23.28	$0.00	$91.95	$10.27	12.6%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$34.82	$0.00	$134.20	$14.28	11.9%

EXHIBIT HS-8

LIFELINE RESIDENTIAL SERVICE TIME OF USE SUPER-PEAK RATE R-8L

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.11				$11.50	$0.08910	$0.08910	$0.11210	$0.040200	$0.00682			
Off-Peak	0.89					$0.03850	$0.03850	$0.06150	$0.020500				
Small	461	461	0	0	$11.50	$20.33	$0.00	$0.00	$10.45	$3.14	$45.42	$36.42	-19.8%
Medium	835	500	335	0	$11.50	$22.05	$14.77	$0.00	$18.94	$5.69	$72.95	$63.95	-12.3%
Large	946	500	446	0	$11.50	$22.05	$19.66	$0.00	$21.45	$6.45	$81.11	$72.11	-11.1%
XLg	980	500	480	0	$11.50	$22.05	$21.16	$0.00	$22.22	$6.68	$83.61	$74.61	-10.8%
AnnAvg	729	500	229	0	$11.50	$22.05	$10.11	$0.00	$16.54	$4.97	$65.17	$56.17	-13.8%
ResAvg	785	500	285	0	$11.50	$22.05	$12.57	$0.00	$17.80	$5.35	$69.27	$60.27	-13.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.11				$15.00	$0.06401	$0.08059	$0.08059	$0.041293	$0.00000				
Off-Peak	0.89					$0.06401	$0.08059	$0.08059	$0.021492				$ Change	% Change
Small	461	461	0	0	$15.00	$29.51	$0.00	$0.00	$10.92	$0.00	$55.43	$40.43	$4.01	11.0%
Medium	835	500	335	0	$15.00	$32.00	$27.00	$0.00	$19.77	$0.00	$93.77	$78.77	$14.82	23.2%
Large	946	500	446	0	$15.00	$32.00	$35.94	$0.00	$22.40	$0.00	$105.34	$90.34	$18.23	25.3%
XLg	980	500	480	0	$15.00	$32.00	$38.68	$0.00	$23.21	$0.00	$108.89	$93.89	$19.28	25.8%
AnnAvg	729	500	229	0	$15.00	$32.00	$18.48	$0.00	$17.27	$0.00	$82.75	$67.75	$11.58	20.6%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$18.59	$0.00	$88.56	$73.56	$13.29	22.1%

EXHIBIT HS-8

LIFELINE RESIDENTIAL SERVICE TIME OF USE SUPER-PEAK RATE R-8L

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000	$11.50	500	1000	>1000					
On-Peak	0.13					$0.09710	$0.09710	$0.12010	$0.080100	$0.00682			
Off-Peak	0.87					$0.04850	$0.04850	$0.07150	$0.022200				
Small	1,305	500	500	305	$11.50	$27.39	$27.39	$23.72	$38.73	$8.90	$137.63	$128.63	-6.5%
Medium	1,464	500	500	464	$11.50	$27.39	$27.39	$36.09	$43.44	$9.98	$155.79	$146.79	-5.8%
Large	1,559	500	500	559	$11.50	$27.39	$27.39	$43.48	$46.26	$10.63	$166.65	$157.65	-5.4%
XLg	1,559	500	500	559	$11.50	$27.39	$27.39	$43.48	$46.26	$10.63	$166.65	$157.65	-5.4%
AnnAvg	729	500	229	0	$11.50	$27.39	$12.56	$0.00	$21.64	$4.97	$78.06	$69.06	-11.5%
ResAvg	1,150	500	500	150	$11.50	$27.39	$27.39	$11.67	$34.13	$7.84	$119.92	$110.92	-7.5%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.13				$15.00	$0.06401	$0.08059	$0.08059	$0.081060	$0.00000				
Off-Peak	0.87					$0.06401	$0.08059	$0.08059	$0.022750					
Small	1,305	500	500	305	$15.00	$32.00	$40.29	$24.58	$39.51	$0.00	$151.38	$136.38	$7.75	6.0%
Medium	1,464	500	500	464	$15.00	$32.00	$40.29	$37.39	$44.33	$0.00	$169.01	$154.01	$7.22	4.9%
Large	1,559	500	500	559	$15.00	$32.00	$40.29	$45.05	$47.20	$0.00	$179.54	$164.54	$6.89	4.4%
XLg	1,559	500	500	559	$15.00	$32.00	$40.29	$45.05	$47.20	$0.00	$179.54	$164.54	$6.89	4.4%
AnnAvg	729	500	229	0	$15.00	$32.00	$18.48	$0.00	$22.08	$0.00	$87.56	$72.56	$3.50	5.1%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$34.82	$0.00	$134.20	$119.20	$8.28	7.5%

EXHIBIT HS-8

SPECIAL RESIDENTIAL ELECTRIC SERVICE RATE R-201A

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05060	$0.05870	$0.07030	$0.07840	$0.031532	$0.00682	
Small	759	500	259	0	0	$10.00	$25.30	$15.20	$0.00	$0.00	$23.93	$5.18	$79.61
Medium	1,110	500	500	110	0	$10.00	$25.30	$29.35	$7.73	$0.00	$35.00	$7.57	$114.95
Large	1,513	500	500	513	0	$10.00	$25.30	$29.35	$36.06	$0.00	$47.71	$10.32	$158.74
XLg	1,820	500	500	820	0	$10.00	$25.30	$29.35	$57.65	$0.00	$57.39	$12.41	$192.10
AnnAvg	946	500	446	0	0	$10.00	$25.30	$26.17	$0.00	$0.00	$29.82	$6.45	$97.74
ResAvg	785	500	285	0	0	$10.00	$25.30	$16.73	$0.00	$0.00	$24.75	$5.35	$82.13

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill		
		500	1000	>1000			500	1000	>1000					$ Change	% Change
						$15.00	$0.06401	$0.08059	$0.08059		$0.026030	$0.00000			
Small	759	500	259	0		$15.00	$32.00	$20.87	$0.00		$19.76	$0.00	$87.63	$8.02	10.1%
Medium	1,110	500	500	110		$15.00	$32.00	$40.29	$8.86		$28.89	$0.00	$125.04	$10.09	8.8%
Large	1,513	500	500	513		$15.00	$32.00	$40.29	$41.34		$39.38	$0.00	$168.01	$9.27	5.8%
XLg	1,820	500	500	820		$15.00	$32.00	$40.29	$66.08		$47.37	$0.00	$200.74	$8.64	4.5%
AnnAvg	946	500	446	0		$15.00	$32.00	$35.92	$0.00		$24.62	$0.00	$107.54	$9.80	10.0%
ResAvg	785	500	285	0		$15.00	$32.00	$22.97	$0.00		$20.43	$0.00	$90.40	$8.27	10.1%

EXHIBIT HS-8

SPECIAL RESIDENTIAL ELECTRIC SERVICE RATE R-201A

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05060	$0.06050	$0.07180	$0.07940	$0.035111	$0.00682	
Small	1,017	500	500	17	0	$10.00	$25.30	$30.25	$1.22	$0.00	$35.71	$6.94	$109.42
Medium	1,505	500	500	505	0	$10.00	$25.30	$30.25	$36.26	$0.00	$52.84	$10.26	$164.91
Large	1,999	500	500	999	0	$10.00	$25.30	$30.25	$71.73	$0.00	$70.19	$13.63	$221.10
XLg	2,349	500	500	1,349	0	$10.00	$25.30	$30.25	$96.86	$0.00	$82.48	$16.02	$260.91
AnnAvg	946	500	446	0	0	$10.00	$25.30	$26.97	$0.00	$0.00	$33.21	$6.45	$101.93
ResAvg	1,150	500	500	150	0	$10.00	$25.30	$30.25	$10.77	$0.00	$40.38	$7.84	$124.54

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill		
		500	1000	>1000			500	1000	>1000						
						$15.00	$0.06401	$0.08059	$0.08059		$0.028694	$0.00000		$ Change	% Change
Small	1,017	500	500	17		$15.00	$32.00	$40.29	$1.37		$29.18	$0.00	$117.84	$8.42	7.7%
Medium	1,505	500	500	505		$15.00	$32.00	$40.29	$40.70		$43.18	$0.00	$171.17	$6.26	3.8%
Large	1,999	500	500	999		$15.00	$32.00	$40.29	$80.51		$57.36	$0.00	$225.16	$4.06	1.8%
XLg	2,349	500	500	1,349		$15.00	$32.00	$40.29	$108.71		$67.40	$0.00	$263.40	$2.49	1.0%
AnnAvg	946	500	446	0		$15.00	$32.00	$35.92	$0.00		$27.14	$0.00	$110.06	$8.13	8.0%
ResAvg	1,150	500	500	150		$15.00	$32.00	$40.29	$12.09		$33.00	$0.00	$132.38	$7.84	6.3%

EXHIBIT HS-8

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE RATE R-201A

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	3500	>3500		500	1000	3500	>3500					
						$10.00	$0.05060	$0.05870	$0.07030	$0.07840	$0.031532	$0.00682			
Small	691	500	191	0	0	$10.00	$25.30	$11.18	$0.00	$0.00	$21.77	$4.71	$72.96	$63.96	-12.3%
Medium	1,009	500	500	9	0	$10.00	$25.30	$29.35	$0.63	$0.00	$31.82	$6.88	$103.98	$94.98	-8.7%
Large	1,342	500	500	342	0	$10.00	$25.30	$29.35	$24.04	$0.00	$42.32	$9.15	$140.16	$131.16	-6.4%
XLg	1,581	500	500	581	0	$10.00	$25.30	$29.35	$40.84	$0.00	$49.85	$10.78	$166.12	$157.12	-5.4%
AnnAvg	862	500	362	0	0	$10.00	$25.30	$21.24	$0.00	$0.00	$27.17	$5.88	$89.59	$80.59	-10.0%
ResAvg	785	500	285	0	0	$10.00	$25.30	$16.73	$0.00	$0.00	$24.75	$5.35	$82.13	$73.13	-11.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000			500	1000	>1000						$ Change	% Change
						$15.00	$0.06401	$0.08059	$0.08059		$0.026030	$0.00000				
Small	691	500	191	0		$15.00	$32.00	$15.35	$0.00		$17.97	$0.00	$80.32	$65.32	$1.36	2.1%
Medium	1,009	500	500	9		$15.00	$32.00	$40.29	$0.73		$26.26	$0.00	$114.28	$99.28	$4.30	4.5%
Large	1,342	500	500	342		$15.00	$32.00	$40.29	$27.56		$34.93	$0.00	$149.78	$134.78	$3.62	2.8%
XLg	1,581	500	500	581		$15.00	$32.00	$40.29	$46.82		$41.15	$0.00	$175.26	$160.26	$3.14	2.0%
AnnAvg	862	500	362	0		$15.00	$32.00	$29.16	$0.00		$22.43	$0.00	$98.59	$83.59	$3.00	3.7%
ResAvg	785	500	285	0		$15.00	$32.00	$22.97	$0.00		$20.43	$0.00	$90.40	$75.40	$2.27	3.1%

EXHIBIT HS-8

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE RATE R-201A

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	3500	>3500		500	1000	3500	>3500					
						$10.00	$0.05060	$0.06050	$0.07180	$0.07940	$0.035111	$0.00682			
Small	877	500	377	0	0	$10.00	$25.30	$22.81	$0.00	$0.00	$30.79	$5.98	$94.88	$85.88	-9.5%
Medium	1,268	500	500	268	0	$10.00	$25.30	$30.25	$19.24	$0.00	$44.52	$8.65	$137.96	$128.96	-6.5%
Large	1,815	500	500	815	0	$10.00	$25.30	$30.25	$58.52	$0.00	$63.73	$12.38	$200.18	$191.18	-4.5%
XLg	2,060	500	500	1,060	0	$10.00	$25.30	$30.25	$76.11	$0.00	$72.33	$14.05	$228.04	$219.04	-3.9%
AnnAvg	862	500	362	0	0	$10.00	$25.30	$21.89	$0.00	$0.00	$30.26	$5.88	$93.33	$84.33	-9.6%
ResAvg	1,150	500	500	150	0	$10.00	$25.30	$30.25	$10.77	$0.00	$40.38	$7.84	$124.54	$115.54	-7.2%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000			500	1000	>1000							
						$15.00	$0.06401	$0.08059	$0.08059		$0.028694	$0.00000				
Small	877	500	377	0		$15.00	$32.00	$30.38	$0.00		$25.16	$0.00	$102.54	$87.54	$1.66	1.9%
Medium	1,268	500	500	268		$15.00	$32.00	$40.29	$21.60		$36.38	$0.00	$145.27	$130.27	$1.31	1.0%
Large	1,815	500	500	815		$15.00	$32.00	$40.29	$65.68		$52.08	$0.00	$205.05	$190.05	-$1.13	-0.6%
XLg	2,060	500	500	1,060		$15.00	$32.00	$40.29	$85.42		$59.11	$0.00	$231.82	$216.82	-$2.22	-1.0%
AnnAvg	862	500	362	0		$15.00	$32.00	$29.16	$0.00		$24.73	$0.00	$100.89	$85.89	$1.56	1.8%
ResAvg	1,150	500	500	150		$15.00	$32.00	$40.29	$12.09		$33.00	$0.00	$132.38	$117.38	$1.84	1.6%

EXHIBIT HS-8

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE RATE R-06-201AF FROZEN

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.04130	$0.04130	$0.04130	$0.027198	$0.00682			
Small	694	500	194	0	$6.90	$20.65	$7.99	$0.00	$18.86	$4.73	$59.13	$50.13	-15.2%
Medium	1,030	500	500	30	$6.90	$20.65	$20.65	$1.24	$28.01	$7.02	$84.47	$75.47	-10.7%
Large	1,310	500	500	310	$6.90	$20.65	$20.65	$12.80	$35.63	$8.93	$105.56	$96.56	-8.5%
XLg	1,524	500	500	524	$6.90	$20.65	$20.65	$21.64	$41.45	$10.39	$121.68	$112.68	-7.4%
AnnAvg	899	500	399	0	$6.90	$20.65	$16.48	$0.00	$24.45	$6.13	$74.61	$65.61	-12.1%
ResAvg	785	500	285	0	$6.90	$20.65	$11.77	$0.00	$21.35	$5.35	$66.02	$57.02	-13.6%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06401	$0.08059	$0.08059	$0.026030	$0.00000				
Small	694	500	194	0	$15.00	$32.00	$15.59	$0.00	$18.05	$0.00	$80.64	$65.64	$15.51	30.9%
Medium	1,030	500	500	30	$15.00	$32.00	$40.29	$2.42	$26.81	$0.00	$116.52	$101.52	$26.05	34.5%
Large	1,310	500	500	310	$15.00	$32.00	$40.29	$24.98	$34.10	$0.00	$146.37	$131.37	$34.81	36.1%
XLg	1,524	500	500	524	$15.00	$32.00	$40.29	$42.23	$39.67	$0.00	$169.19	$154.19	$41.51	36.8%
AnnAvg	899	500	399	0	$15.00	$32.00	$32.16	$0.00	$23.40	$0.00	$102.56	$87.56	$21.95	33.5%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$20.43	$0.00	$90.40	$75.40	$18.38	32.2%

EXHIBIT HS-8

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE RATE R-06-201AF FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
	Mid-Summer				$6.90	$0.06110	$0.06110	$0.06110	$0.033198	$0.00682			
Small	940	500	440	0	$6.90	$30.55	$26.88	$0.00	$31.21	$6.41	$101.95	$92.95	-8.8%
Medium	1,471	500	500	471	$6.90	$30.55	$30.55	$28.75	$48.82	$10.03	$155.60	$146.60	-5.8%
Large	1,869	500	500	869	$6.90	$30.55	$30.55	$53.10	$62.05	$12.75	$195.90	$186.90	-4.6%
XLg	2,135	500	500	1,135	$6.90	$30.55	$30.55	$69.35	$70.88	$14.56	$222.79	$213.79	-4.0%
AnnAvg	899	500	399	0	$6.90	$30.55	$24.38	$0.00	$29.85	$6.13	$97.81	$88.81	-9.2%
ResAvg	1,150	500	500	150	$6.90	$30.55	$30.55	$9.17	$38.18	$7.84	$123.19	$114.19	-7.3%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06401	$0.08059	$0.08059	$0.02869	$0.00000				
Small	940	500	440	0	$15.00	$32.00	$35.46	$0.00	$26.97	$0.00	$109.43	$94.43	$1.48	1.6%
Medium	1,471	500	500	471	$15.00	$32.00	$40.29	$37.92	$42.19	$0.00	$167.40	$152.40	$5.80	4.0%
Large	1,869	500	500	869	$15.00	$32.00	$40.29	$70.03	$53.63	$0.00	$210.95	$195.95	$9.05	4.8%
XLg	2,135	500	500	1,135	$15.00	$32.00	$40.29	$91.47	$61.26	$0.00	$240.02	$225.02	$11.23	5.3%
AnnAvg	899	500	399	0	$15.00	$32.00	$32.16	$0.00	$25.80	$0.00	$104.96	$89.96	$1.15	1.3%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$33.00	$0.00	$132.38	$117.38	$3.19	2.8%

EXHIBIT HS-8

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE RATE R-08-201A FROZEN

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.04130	$0.04130	$0.04130	$0.027198	$0.00682			
Small	1,201	500	500	201	$6.90	$20.65	$20.65	$8.28	$32.65	$8.19	$97.32	$68.12	-30.0%
Medium	1,630	500	500	630	$6.90	$20.65	$20.65	$26.02	$44.33	$11.12	$129.67	$90.77	-30.0%
Large	2,051	500	500	1,051	$6.90	$20.65	$20.65	$43.41	$55.78	$13.99	$161.38	$145.24	-10.0%
XLg	2,310	500	500	1,310	$6.90	$20.65	$20.65	$54.10	$62.83	$15.75	$180.88	$162.79	-10.0%
AnnAvg	1,382	500	500	382	$6.90	$20.65	$20.65	$15.78	$37.59	$9.43	$111.00	$77.70	-30.0%
ResAvg	785	500	285	0	$6.90	$20.65	$11.77	$0.00	$21.35	$5.35	$66.02	$42.91	-35.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06401	$0.08059	$0.08059	$0.026030	$0.00000				
Small	1,201	500	500	201	$15.00	$32.00	$40.29	$16.16	$31.25	$0.00	$134.70	$103.70	$35.58	52.2%
Medium	1,630	500	500	630	$15.00	$32.00	$40.29	$50.77	$42.43	$0.00	$180.49	$149.49	$58.72	64.7%
Large	2,051	500	500	1,051	$15.00	$32.00	$40.29	$84.70	$53.39	$0.00	$225.38	$194.38	$49.14	33.8%
XLg	2,310	500	500	1,310	$15.00	$32.00	$40.29	$105.57	$60.13	$0.00	$252.99	$221.99	$59.20	36.4%
AnnAvg	1,382	500	500	382	$15.00	$32.00	$40.29	$30.80	$35.98	$0.00	$154.07	$123.07	$45.37	58.4%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$20.43	$0.00	$90.40	$59.40	$16.49	38.4%

EXHIBIT HS-8

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE RATE R-08-201A FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
	Mid-Summer				$6.90	$0.06110	$0.06110	$0.06110	$0.033198	$0.00682			
Small	1,586	500	500	586	$6.90	$30.55	$30.55	$35.80	$52.65	$10.82	$167.27	$117.09	-30.0%
Medium	2,062	500	500	1,062	$6.90	$30.55	$30.55	$64.89	$68.45	$14.06	$215.40	$193.86	-10.0%
Large	2,487	500	500	1,487	$6.90	$30.55	$30.55	$90.86	$82.56	$16.96	$258.38	$232.54	-10.0%
XLg	2,710	500	500	1,710	$6.90	$30.55	$30.55	$104.48	$89.97	$18.48	$280.93	$252.84	-10.0%
AnnAvg	1,382	500	500	382	$6.90	$30.55	$30.55	$23.35	$45.88	$9.43	$146.66	$102.66	-30.0%
ResAvg	1,150	500	500	150	$6.90	$30.55	$30.55	$9.17	$38.18	$7.84	$123.19	$86.23	-30.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06401	$0.08059	$0.08059	$0.028694	$0.00000			$ Change	% Change
Small	1,586	500	500	586	$15.00	$32.00	$40.29	$47.22	$45.51	$0.00	$180.02	$149.02	$31.93	27.3%
Medium	2,062	500	500	1,062	$15.00	$32.00	$40.29	$85.58	$59.17	$0.00	$232.04	$201.04	$7.18	3.7%
Large	2,487	500	500	1,487	$15.00	$32.00	$40.29	$119.83	$71.36	$0.00	$278.48	$247.48	$14.94	6.4%
XLg	2,710	500	500	1,710	$15.00	$32.00	$40.29	$137.81	$77.76	$0.00	$302.86	$271.86	$19.02	7.5%
AnnAvg	1,382	500	500	382	$15.00	$32.00	$40.29	$30.80	$39.66	$0.00	$157.75	$126.75	$24.09	23.5%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$33.00	$0.00	$132.38	$101.38	$15.15	17.6%

EXHIBIT HS-8

SPECIAL RESIDENTIAL ELECTRIC SERVICE TIME OF USE RATE R-201B

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill
		500	1000	>1000		500	1000	>1000			
On-Peak	0.27				$11.50	$0.04830	$0.04830	$0.04830	$0.032893	$0.00682	
Off-Peak	0.73					$0.03550	$0.03550	$0.03550	$0.027092		
Small	838	500	338	0	$11.50	$19.47	$13.14	$0.00	$24.00	$5.71	$73.82
Medium	1,258	500	500	258	$11.50	$19.47	$19.47	$10.05	$36.04	$8.58	$105.11
Large	1,800	500	500	800	$11.50	$19.47	$19.47	$31.15	$51.57	$12.28	$145.44
XLg	2,221	500	500	1,221	$11.50	$19.47	$19.47	$47.55	$63.63	$15.15	$176.77
AnnAvg	1,097	500	500	97	$11.50	$19.47	$19.47	$3.76	$31.42	$7.48	$93.10
ResAvg	785	500	285	0	$11.50	$19.47	$11.10	$0.00	$22.49	$5.35	$69.91

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	$ Change	% Change
		500	1000	>1000		500	1000	>1000					
On-Peak	0.27				$15.00	$0.06401	$0.08059	$0.08059	$0.027114	$0.00000			
Off-Peak	0.73					$0.06401	$0.08059	$0.08059	$0.022474			$ Change	% Change
Small	838	500	338	0	$15.00	$32.00	$27.20	$0.00	$19.87	$0.00	$94.07	$20.25	27.4%
Medium	1,258	500	500	258	$15.00	$32.00	$40.29	$20.79	$29.84	$0.00	$137.92	$32.81	31.2%
Large	1,800	500	500	800	$15.00	$32.00	$40.29	$64.47	$42.70	$0.00	$194.46	$49.02	33.7%
XLg	2,221	500	500	1,221	$15.00	$32.00	$40.29	$98.40	$52.68	$0.00	$238.37	$61.60	34.8%
AnnAvg	1,097	500	500	97	$15.00	$32.00	$40.29	$7.78	$26.01	$0.00	$121.08	$27.98	30.1%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$18.62	$0.00	$88.59	$18.68	26.7%

EXHIBIT HS-8

SPECIAL RESIDENTIAL ELECTRIC SERVICE TIME OF USE RATE R-201B

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill
		500	1000	>1000	$11.50	500	1000	>1000			
On-Peak	0.23					$0.05680	$0.05680	$0.05680	$0.050669	$0.00682	
Off-Peak	0.77					$0.04400	$0.04400	$0.04400	$0.026679		
Small	1,066	500	500	66	$11.50	$23.45	$23.45	$3.10	$34.25	$7.27	$103.02
Medium	1,609	500	500	609	$11.50	$23.45	$23.45	$28.57	$51.69	$10.97	$149.63
Large	2,283	500	500	1,283	$11.50	$23.45	$23.45	$60.18	$73.34	$15.57	$207.49
XLg	2,790	500	500	1,790	$11.50	$23.45	$23.45	$83.96	$89.63	$19.03	$251.02
AnnAvg	1,097	500	500	97	$11.50	$23.45	$23.45	$4.53	$35.23	$7.48	$105.64
ResAvg	1,150	500	500	150	$11.50	$23.45	$23.45	$7.04	$36.94	$7.84	$110.22

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill		
		500	1000	>1000		500	1000	>1000					
On-Peak	0.23				$15.00	$0.06401	$0.08059	$0.08059	$0.041328	$0.00000			
Off-Peak	0.77					$0.06401	$0.08059	$0.08059	$0.021400			$ Change	% Change
Small	1,066	500	500	66	$15.00	$32.00	$40.29	$5.32	$27.63	$0.00	$120.24	$17.22	16.7%
Medium	1,609	500	500	609	$15.00	$32.00	$40.29	$49.08	$41.71	$0.00	$178.08	$28.45	19.0%
Large	2,283	500	500	1,283	$15.00	$32.00	$40.29	$103.39	$59.18	$0.00	$249.86	$42.37	20.4%
XLg	2,790	500	500	1,790	$15.00	$32.00	$40.29	$144.25	$72.33	$0.00	$303.87	$52.85	21.1%
AnnAvg	1,097	500	500	97	$15.00	$32.00	$40.29	$7.78	$28.43	$0.00	$123.50	$17.86	16.9%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$29.81	$0.00	$129.19	$18.97	17.2%

EXHIBIT HS-8

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE TIME OF USE RATE R-201BL

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.27				$11.50	$0.04830	$0.04830	$0.04830	$0.032893	$0.00682			
Off-Peak	0.73					$0.03550	$0.03550	$0.03550	$0.027092				
Small	915	500	415	0	$11.50	$19.47	$16.16	$0.00	$26.22	$6.24	$79.59	$70.59	-11.3%
Medium	1,231	500	500	231	$11.50	$19.47	$19.47	$9.00	$35.27	$8.40	$103.11	$94.11	-8.7%
Large	1,524	500	500	524	$11.50	$19.47	$19.47	$20.40	$43.66	$10.39	$124.89	$115.89	-7.2%
XLg	2,733	500	500	1,733	$11.50	$19.47	$19.47	$67.48	$78.30	$18.64	$214.86	$205.86	-4.2%
AnnAvg	1,370	500	500	370	$11.50	$19.47	$19.47	$14.41	$39.25	$9.34	$113.44	$104.44	-7.9%
ResAvg	785	500	285	0	$11.50	$19.47	$11.10	$0.00	$22.49	$5.35	$69.91	$60.91	-12.9%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.27				$15.00	$0.06401	$0.08059	$0.08059	$0.027114	$0.00000				
Off-Peak	0.73					$0.06401	$0.08059	$0.08059	$0.022474					
Small	915	500	415	0	$15.00	$32.00	$33.44	$0.00	$21.70	$0.00	$102.14	$87.14	$16.55	23.4%
Medium	1,231	500	500	231	$15.00	$32.00	$40.29	$18.62	$29.20	$0.00	$135.11	$120.11	$26.00	27.6%
Large	1,524	500	500	524	$15.00	$32.00	$40.29	$42.23	$36.15	$0.00	$165.67	$150.67	$34.78	30.0%
XLg	2,733	500	500	1,733	$15.00	$32.00	$40.29	$139.66	$64.83	$0.00	$291.78	$276.78	$70.92	34.5%
AnnAvg	1,370	500	500	370	$15.00	$32.00	$40.29	$29.81	$32.50	$0.00	$149.60	$134.60	$30.16	28.9%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$18.62	$0.00	$88.59	$73.59	$12.68	20.8%

EXHIBIT HS-8

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE TIME OF USE RATE R-201BL

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000	$11.50	500	1000	>1000					
On-Peak	0.23					$0.05680	$0.05680	$0.05680	$0.050669	$0.00682			
Off-Peak	0.77					$0.04400	$0.04400	$0.04400	$0.026679				
Small	1,119	500	500	119	$11.50	$23.45	$23.45	$5.58	$35.95	$7.63	$107.56	$98.56	-8.4%
Medium	3,060	500	500	2,060	$11.50	$23.45	$23.45	$96.63	$98.30	$20.87	$274.20	$265.20	-3.3%
Large	3,869	500	500	2,869	$11.50	$23.45	$23.45	$134.57	$124.29	$26.39	$343.65	$334.65	-2.6%
XLg	3,869	500	500	2,869	$11.50	$23.45	$23.45	$134.57	$124.29	$26.39	$343.65	$334.65	-2.6%
AnnAvg	1,370	500	500	370	$11.50	$23.45	$23.45	$17.35	$44.01	$9.34	$129.10	$120.10	-7.0%
ResAvg	1,150	500	500	150	$11.50	$23.45	$23.45	$7.04	$36.94	$7.84	$110.22	$101.22	-8.2%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000					$ Change	% Change
On-Peak	0.23				$15.00	$0.06401	$0.08059	$0.08059	$0.041328	$0.00000				
Off-Peak	0.77					$0.06401	$0.08059	$0.08059	$0.021400					
Small	1,119	500	500	119	$15.00	$32.00	$40.29	$9.59	$29.01	$0.00	$125.89	$110.89	$12.33	12.5%
Medium	3,060	500	500	2,060	$15.00	$32.00	$40.29	$166.01	$79.33	$0.00	$332.63	$317.63	$52.43	19.8%
Large	3,869	500	500	2,869	$15.00	$32.00	$40.29	$231.21	$100.30	$0.00	$418.80	$403.80	$69.15	20.7%
XLg	3,869	500	500	2,869	$15.00	$32.00	$40.29	$231.21	$100.30	$0.00	$418.80	$403.80	$69.15	20.7%
AnnAvg	1,370	500	500	370	$15.00	$32.00	$40.29	$29.81	$35.51	$0.00	$152.61	$137.61	$17.51	14.6%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$29.81	$0.00	$129.19	$114.19	$12.97	12.8%

EXHIBIT HS-8

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE TIME OF USE RATE R-06-201BF

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.24				$8.78	$0.06520	$0.06520	$0.06520	$0.040698	$0.00682			
Shldr-Peak	N/A												
Off-Peak	0.76					$0.01530	$0.01530	$0.01530	$0.020698				
Small	515	500	15	0	$8.78	$13.52	$0.41	$0.00	$13.08	$3.51	$39.30	$30.30	-22.9%
Medium	1,064	500	500	64	$8.78	$13.52	$13.52	$1.73	$27.03	$7.26	$71.84	$62.84	-12.5%
Large	1,311	500	500	311	$8.78	$13.52	$13.52	$8.40	$33.29	$8.94	$86.45	$77.45	-10.4%
XLg	1,647	500	500	647	$8.78	$13.52	$13.52	$17.50	$41.84	$11.23	$106.39	$97.39	-8.5%
AnnAvg	745	500	245	0	$8.78	$13.52	$6.62	$0.00	$18.92	$5.08	$52.92	$43.92	-17.0%
ResAvg	785	500	285	0	$8.78	$13.52	$7.71	$0.00	$19.94	$5.35	$55.30	$46.30	-16.3%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.27				$15.00	$0.06401	$0.08059	$0.08059	$0.028809	$0.00000				
Off-Peak	0.73					$0.06401	$0.08059	$0.08059	$0.023878				$ Change	% Change
Small	515	500	15	0	$15.00	$32.00	$1.21	$0.00	$12.98	$0.00	$61.19	$46.19	$15.89	52.4%
Medium	1,064	500	500	64	$15.00	$32.00	$40.29	$5.16	$26.82	$0.00	$119.27	$104.27	$41.43	65.9%
Large	1,311	500	500	311	$15.00	$32.00	$40.29	$25.03	$33.03	$0.00	$145.35	$130.35	$52.90	68.3%
XLg	1,647	500	500	647	$15.00	$32.00	$40.29	$52.14	$41.51	$0.00	$180.94	$165.94	$68.55	70.4%
AnnAvg	745	500	245	0	$15.00	$32.00	$19.74	$0.00	$18.77	$0.00	$85.51	$70.51	$26.59	60.5%
ResAvg	785	500	285	0	$15.00	$32.00	$22.97	$0.00	$19.78	$0.00	$89.75	$74.75	$28.45	61.4%

EXHIBIT HS-8

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE TIME OF USE RATE R-06-201BF

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.18				$8.78	$0.13690	$0.13690	$0.13690	$0.055698	$0.00682			
Shldr-Peak	0.09					$0.07470	$0.07470	$0.07470	$0.048198				
Off-Peak	0.72					$0.03830	$0.03830	$0.03830	$0.023198				
Small	559	500	59	0	$8.78	$29.89	$3.50	$0.00	$17.57	$3.81	$63.55	$54.55	-14.2%
Medium	1,492	500	500	492	$8.78	$29.89	$29.89	$29.41	$46.95	$10.18	$155.10	$146.10	-5.8%
Large	1,824	500	500	824	$8.78	$29.89	$29.89	$49.26	$57.39	$12.44	$187.65	$178.65	-4.8%
XLg	1,862	500	500	862	$8.78	$29.89	$29.89	$51.54	$58.59	$12.70	$191.39	$182.39	-4.7%
AnnAvg	745	500	245	0	$8.78	$29.89	$14.64	$0.00	$23.44	$5.08	$81.83	$72.83	-11.0%
ResAvg	1,150	500	500	150	$8.78	$29.89	$29.89	$8.97	$36.19	$7.84	$121.56	$112.56	-7.4%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.23				$15.00	$0.06401	$0.08059	$0.08059	$0.043911	$0.00000				
Off-Peak	0.77					$0.06401	$0.08059	$0.08059	$0.022738					
Small	559	500	59	0	$15.00	$32.00	$4.71	$0.00	$15.38	$0.00	$67.09	$52.09	-$2.46	-4.5%
Medium	1,492	500	500	492	$15.00	$32.00	$40.29	$39.65	$41.10	$0.00	$168.04	$153.04	$6.94	4.8%
Large	1,824	500	500	824	$15.00	$32.00	$40.29	$66.40	$50.24	$0.00	$203.93	$188.93	$10.28	5.8%
XLg	1,862	500	500	862	$15.00	$32.00	$40.29	$69.47	$51.29	$0.00	$208.05	$193.05	$10.66	5.8%
AnnAvg	745	500	245	0	$15.00	$32.00	$19.74	$0.00	$20.52	$0.00	$87.26	$72.26	-$0.57	-0.8%
ResAvg	1,150	500	500	150	$15.00	$32.00	$40.29	$12.09	$31.68	$0.00	$131.06	$116.06	$3.50	3.1%

EXHIBIT HS-8

Small General Service RATE GS-10

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.05700	$0.07900	$0.031532	$0.00682	
Xsm	190	190	0	$15.50	$10.83	$0.00	$5.99	$1.30	$33.62
Small	687	500	187	$15.50	$28.50	$14.77	$21.66	$4.69	$85.12
Medium	1,744	500	1,244	$15.50	$28.50	$98.28	$54.99	$11.89	$209.16
Large	3,680	500	3,180	$15.50	$28.50	$251.22	$116.04	$25.10	$436.36
XLg	5,157	500	4,657	$15.50	$28.50	$367.90	$162.61	$35.17	$609.68
AnnAvg	1,568	500	1,068	$15.50	$28.50	$84.37	$49.44	$10.69	$188.50
SGSAvg	1,340	500	840	$15.50	$28.50	$66.36	$42.25	$9.14	$161.75

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
				$27.00	$0.05690	$0.07790	$0.032537	$0.00000			
										$ Change	% Change
Xsm	190	190	0	$27.00	$10.81	$0.00	$6.18	$0.00	$43.99	$10.37	30.8%
Small	687	500	187	$27.00	$28.45	$14.57	$22.35	$0.00	$92.37	$7.25	8.5%
Medium	1,744	500	1,244	$27.00	$28.45	$96.91	$56.74	$0.00	$209.10	-$0.06	0.0%
Large	3,680	500	3,180	$27.00	$28.45	$247.72	$119.74	$0.00	$422.91	-$13.45	-3.1%
XLg	5,157	500	4,657	$27.00	$28.45	$362.78	$167.79	$0.00	$586.02	-$23.66	-3.9%
AnnAvg	1,568	500	1,068	$27.00	$28.45	$83.20	$51.02	$0.00	$189.67	$1.17	0.6%
SGSAvg	1,340	500	840	$27.00	$28.45	$65.44	$43.60	$0.00	$164.49	$2.74	1.7%

EXHIBIT HS-8

Small General Service RATE GS-10

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.07700	$0.09780	$0.035111	$0.00682	
Xsm	216	216	0	$15.50	$16.63	$0.00	$7.58	$1.47	$41.18
Small	882	500	382	$15.50	$38.50	$37.36	$30.97	$6.02	$128.35
Medium	2,354	500	1,854	$15.50	$38.50	$181.32	$82.65	$16.05	$334.02
Large	4,820	500	4,320	$15.50	$38.50	$422.50	$169.24	$32.87	$678.61
XLg	6,690	500	6,190	$15.50	$38.50	$605.38	$234.89	$45.63	$939.90
AnnAvg	1,568	500	1,068	$15.50	$38.50	$104.45	$55.05	$10.69	$224.19
SGSAvg	1,886	500	1,386	$15.50	$38.50	$135.51	$66.21	$12.86	$268.58

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
				$27.00	$0.07690	$0.09690	$0.035868	$0.00000			
										$ Change	% Change
Xsm	216	216	0	$27.00	$16.61	$0.00	$7.75	$0.00	$51.36	$10.18	24.7%
Small	882	500	382	$27.00	$38.45	$37.02	$31.64	$0.00	$134.11	$5.76	4.5%
Medium	2,354	500	1,854	$27.00	$38.45	$179.65	$84.43	$0.00	$329.53	-$4.49	-1.3%
Large	4,820	500	4,320	$27.00	$38.45	$418.60	$172.88	$0.00	$656.93	-$21.68	-3.2%
XLg	6,690	500	6,190	$27.00	$38.45	$599.80	$239.96	$0.00	$905.21	-$34.69	-3.7%
AnnAvg	1,568	500	1,068	$27.00	$38.45	$103.49	$56.24	$0.00	$225.18	$0.99	0.4%
SGSAvg	1,886	500	1,386	$27.00	$38.45	$134.26	$67.63	$0.00	$267.34	-$1.24	-0.5%

EXHIBIT HS-8

SMALL GENERAL SERVICE DEMAND

WINTER

BILL IMPACTS CURRENT GS-10 RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill
			500	>500					500	>500					
								$15.50	$0.05700	$0.07900			$0.031532	$0.00682	
Xsm	0.21	190	190	0	1.2			$15.50	$10.83	$0.00			$5.99	$1.30	$33.62
Small	0.29	687	500	187	3.2			$15.50	$28.50	$14.77			$21.66	$4.69	$85.12
Medium	0.37	1,744	500	1,244	6.5			$15.50	$28.50	$98.28			$54.99	$11.89	$209.16
Large	0.45	3,680	500	3,180	11.3			$15.50	$28.50	$251.22			$116.04	$25.10	$436.36
XLg	0.49	5,157	500	4,657	14.5			$15.50	$28.50	$367.90			$162.61	$35.17	$609.68
AnnAvg	0.36	1,568	500	1,068	6.0			$15.50	$28.50	$84.37			$49.44	$10.69	$188.50
SGSAvg	0.35	1,340	500	840	5.3			$15.50	$28.50	$66.36			$42.25	$9.14	$161.75

BILL IMPACTS PROPOSED RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill		
			500	>500		7.0	> 7.0		500	>500	7.0	> 7.0					
								$27.00	$0.04777	$0.04777	$9.60	$13.75	$0.032537	$0.00000			
																$ Change	% Change
Xsm	0.21	190	190	0	1.2	1.2	0.0	$27.00	$9.08	$0.00	$11.90	$0.00	$6.18	$0.00	$54.16	$20.54	61.1%
Small	0.29	687	500	187	3.2	3.2	0.0	$27.00	$23.89	$8.93	$31.01	$0.00	$22.35	$0.00	$113.18	$28.06	33.0%
Medium	0.37	1,744	500	1,244	6.5	6.5	0.0	$27.00	$23.89	$59.43	$62.11	$0.00	$56.74	$0.00	$229.17	$20.01	9.6%
Large	0.45	3,680	500	3,180	11.3	7.0	4.3	$27.00	$23.89	$151.91	$67.20	$58.85	$119.74	$0.00	$448.59	$12.23	2.8%
XLg	0.49	5,157	500	4,657	14.5	7.0	7.5	$27.00	$23.89	$222.46	$67.20	$103.26	$167.79	$0.00	$611.60	$1.92	0.3%
AnnAvg	0.36	1,568	500	1,068	6.0	6.0	0.0	$27.00	$23.89	$51.02	$57.41	$0.00	$51.02	$0.00	$210.34	$21.84	11.6%
SGSAvg	0.35	1,340	500	840	5.3	5.3	0.0	$27.00	$23.89	$40.13	$51.07	$0.00	$43.60	$0.00	$185.69	$23.94	14.8%

EXHIBIT HS-8

SMALL GENERAL SERVICE DEMAND

SUMMER

BILL IMPACTS CURRENT GS-10 RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill
			500	>500					500	>500					
								$15.50	$0.07700	$0.09780			$0.035111	$0.00682	
Xsm	0.22	216	216	0	1.4			$15.50	$16.63	$0.00			$7.58	$1.47	$41.18
Small	0.31	882	500	382	3.9			$15.50	$38.50	$37.36			$30.97	$6.02	$128.35
Medium	0.40	2,354	500	1,854	8.1			$15.50	$38.50	$181.32			$82.65	$16.05	$334.02
Large	0.48	4,820	500	4,320	13.8			$15.50	$38.50	$422.50			$169.24	$32.87	$678.61
XLg	0.52	6,690	500	6,190	17.6			$15.50	$38.50	$605.38			$234.89	$45.63	$939.90
AnnAvg	0.36	1,568	500	1,068	6.0			$15.50	$38.50	$104.45			$55.05	$10.69	$224.19
SGSAvg	0.38	1,886	500	1,386	6.9			$15.50	$38.50	$135.51			$66.21	$12.86	$268.58

BILL IMPACTS PROPOSED RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill		
			500	>500		7.0	> 7.0		500	>500	7.0	> 7.0					
								$27.00	$0.05777	$0.05777	$9.60	$13.75	$0.035868	$0.00000			
																$ Change	% Change
Xsm	0.22	216	216	0	1.4	1.4	0.0	$27.00	$12.48	$0.00	$13.06	$0.00	$7.75	$0.00	$60.29	$19.11	46.4%
Small	0.31	882	500	382	3.9	3.9	0.0	$27.00	$28.89	$22.07	$37.34	$0.00	$31.64	$0.00	$146.94	$18.59	14.5%
Medium	0.40	2,354	500	1,854	8.1	7.0	1.1	$27.00	$28.89	$107.11	$67.20	$14.99	$84.43	$0.00	$329.62	-$4.40	-1.3%
Large	0.48	4,820	500	4,320	13.8	7.0	6.8	$27.00	$28.89	$249.57	$67.20	$93.36	$172.88	$0.00	$638.90	-$39.71	-5.9%
XLg	0.52	6,690	500	6,190	17.6	7.0	10.6	$27.00	$28.89	$357.60	$67.20	$145.89	$239.96	$0.00	$866.54	-$73.36	-7.8%
AnnAvg	0.36	1,568	500	1,068	6.0	6.0	0.0	$27.00	$28.89	$61.70	$57.41	$0.00	$56.24	$0.00	$231.24	$7.05	3.1%
SGSAvg	0.38	1,886	500	1,386	6.9	6.9	0.0	$27.00	$28.89	$80.05	$65.86	$0.00	$67.63	$0.00	$269.43	$0.85	0.3%

EXHIBIT HS-8

Small General Service (Municipal Transitional Adjustment) RATE GSM-10

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.05700	$0.07900	$0.031532	$0.00682	
Xsm	190	190	0	$15.50	$10.83	$0.00	$5.99	$1.30	$30.63
Small	687	500	187	$15.50	$28.50	$14.77	$21.66	$4.69	$73.63
Medium	1,744	500	1,244	$15.50	$28.50	$98.28	$54.99	$11.89	$177.21
Large	3,680	500	3,180	$15.50	$28.50	$251.22	$116.04	$25.10	$366.92
XLg	5,157	500	4,657	$15.50	$28.50	$367.90	$162.61	$35.17	$511.64
AnnAvg	1,568	500	1,068	$15.50	$28.50	$84.37	$49.44	$10.69	$159.96
SGSAvg	1,340	500	840	$15.50	$28.50	$66.36	$42.25	$9.14	$137.62

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
				$27.00	$0.05690	$0.07790	$0.032537	$0.00000			
										$ Change	% Change
Xsm	190	190	0	$27.00	$10.81	$0.00	$6.18	$0.00	$43.99	$13.36	43.6%
Small	687	500	187	$27.00	$28.45	$14.57	$22.35	$0.00	$92.37	$18.74	25.4%
Medium	1,744	500	1,244	$27.00	$28.45	$96.91	$56.74	$0.00	$209.10	$31.89	18.0%
Large	3,680	500	3,180	$27.00	$28.45	$247.72	$119.74	$0.00	$422.91	$55.99	15.3%
XLg	5,157	500	4,657	$27.00	$28.45	$362.78	$167.79	$0.00	$586.02	$74.38	14.5%
AnnAvg	1,568	500	1,068	$27.00	$28.45	$83.20	$51.02	$0.00	$189.67	$29.72	18.6%
SGSAvg	1,340	500	840	$27.00	$28.45	$65.44	$43.60	$0.00	$164.49	$26.87	19.5%

EXHIBIT HS-8

Small General Service (Municipal Transitional Adjustment) RATE GSM-10

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.07700	$0.09780	$0.035111	$0.00682	
Xsm	216	216	0	$15.50	$16.63	$0.00	$7.58	$1.47	$36.94
Small	882	500	382	$15.50	$38.50	$37.36	$30.97	$6.02	$109.73
Medium	2,354	500	1,854	$15.50	$38.50	$181.32	$82.65	$16.05	$281.46
Large	4,820	500	4,320	$15.50	$38.50	$422.50	$169.24	$32.87	$569.20
XLg	6,690	500	6,190	$15.50	$38.50	$605.38	$234.89	$45.63	$787.37
AnnAvg	1,568	500	1,068	$15.50	$38.50	$104.45	$55.05	$10.69	$189.76
SGSAvg	1,886	500	1,386	$15.50	$38.50	$135.51	$66.21	$12.86	$226.82

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
				$27.00	$0.07690	$0.09690	$0.035868	$0.00000			
										$ Change	% Change
Xsm	216	216	0	$27.00	$16.61	$0.00	$7.75	$0.00	$51.36	$14.42	39.0%
Small	882	500	382	$27.00	$38.45	$37.02	$31.64	$0.00	$134.11	$24.38	22.2%
Medium	2,354	500	1,854	$27.00	$38.45	$179.65	$84.43	$0.00	$329.53	$48.07	17.1%
Large	4,820	500	4,320	$27.00	$38.45	$418.60	$172.88	$0.00	$656.93	$87.73	15.4%
XLg	6,690	500	6,190	$27.00	$38.45	$599.80	$239.96	$0.00	$905.21	$117.84	15.0%
AnnAvg	1,568	500	1,068	$27.00	$38.45	$103.49	$56.24	$0.00	$225.18	$35.42	18.7%
SGSAvg	1,886	500	1,386	$27.00	$38.45	$134.26	$67.63	$0.00	$267.34	$40.52	17.9%

EXHIBIT HS-8

Mobile Home Parks Service Rate GS-11 Frozen

WINTER

	BILL IMPACTS CURRENT RATES					
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		$15.50	$0.06200	$0.031532	$0.00682	
Xsm	3,067	$15.50	$190.15	$96.71	$20.92	$323.28
Small	6,520	$15.50	$404.24	$205.59	$44.47	$669.80
Medium	11,218	$15.50	$695.52	$353.73	$76.51	$1,141.26
Large	18,640	$15.50	$1,155.68	$587.76	$127.12	$1,886.06
XLg	27,080	$15.50	$1,678.96	$853.89	$184.69	$2,733.04
AnnAvg	13,623	$15.50	$844.60	$429.55	$92.91	$1,382.56
SGSAvg	12,611	$15.50	$781.85	$397.64	$86.00	$1,280.99

	BILL IMPACTS PROPOSED RATES							
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill		
		$27.00	$0.08040	$0.032537	$0.00000		$ Change	% Change
Xsm	3,067	$27.00	$246.58	$99.79	$0.00	$373.37	$50.09	15.5%
Small	6,520	$27.00	$524.20	$212.14	$0.00	$763.34	$93.54	14.0%
Medium	11,218	$27.00	$901.92	$365.00	$0.00	$1,293.92	$152.66	13.4%
Large	18,640	$27.00	$1,498.64	$606.49	$0.00	$2,132.13	$246.07	13.0%
XLg	27,080	$27.00	$2,177.20	$881.10	$0.00	$3,085.30	$352.26	12.9%
AnnAvg	13,623	$27.00	$1,095.24	$443.24	$0.00	$1,565.48	$182.92	13.2%
SGSAvg	12,611	$27.00	$1,013.88	$410.31	$0.00	$1,451.19	$170.20	13.3%

EXHIBIT HS-8

Mobile Home Parks Service Rate GS-11 Frozen

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		$15.50	$0.08200	$0.035111	$0.00682	
Xsm	3,900	$15.50	$319.80	$136.93	$26.60	$498.83
Small	8,480	$15.50	$695.36	$297.74	$57.83	$1,066.43
Medium	17,200	$15.50	$1,410.40	$603.91	$117.30	$2,147.11
Large	26,720	$15.50	$2,191.04	$938.17	$182.23	$3,326.94
XLg	35,920	$15.50	$2,945.44	$1,261.19	$244.97	$4,467.10
AnnAvg	13,623	$15.50	$1,117.05	$478.30	$92.91	$1,703.76
SGSAvg	15,040	$15.50	$1,233.31	$528.08	$102.58	$1,879.47

BILL IMPACTS PROPOSED RATES

	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		$27.00	$0.08040	$0.035868	$0.00000			
Xsm	3,900	$27.00	$313.56	$139.89	$0.00	$480.45	-$18.38	-3.7%
Small	8,480	$27.00	$681.78	$304.16	$0.00	$1,012.94	-$53.49	-5.0%
Medium	17,200	$27.00	$1,382.86	$616.93	$0.00	$2,026.79	-$120.32	-5.6%
Large	26,720	$27.00	$2,148.26	$958.39	$0.00	$3,133.65	-$193.29	-5.8%
XLg	35,920	$27.00	$2,887.93	$1,288.38	$0.00	$4,203.31	-$263.79	-5.9%
AnnAvg	13,623	$27.00	$1,095.24	$488.61	$0.00	$1,610.85	-$92.91	-5.5%
SGSAvg	15,040	$27.00	$1,209.23	$539.47	$0.00	$1,775.70	-$103.77	-5.5%

EXHIBIT HS-8

Municipal Water Pumping Rate GS-43

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		$15.50	$0.04800	$0.031532	$0.00682	
Xsm	90	$15.50	$4.32	$2.84	$0.61	$23.27
Small	1,440	$15.50	$69.12	$45.41	$9.82	$139.85
Medium	10,840	$15.50	$520.32	$341.81	$73.93	$951.56
Large	34,240	$15.50	$1,643.52	$1,079.66	$233.52	$2,972.20
XLg	56,800	$15.50	$2,726.40	$1,791.02	$387.38	$4,920.30
AnnAvg	14,343	$15.50	$688.47	$452.27	$97.82	$1,254.06
SGSAvg	12,251	$15.50	$588.04	$386.30	$83.55	$1,073.39

BILL IMPACTS PROPOSED RATES

	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		$27.00	$0.05700	$0.032537	$0.00000			
Xsm	90	$27.00	$5.13	$2.93	$0.00	$35.06	$11.79	50.7%
Small	1,440	$27.00	$82.08	$46.85	$0.00	$155.93	$16.08	11.5%
Medium	10,840	$27.00	$617.87	$352.70	$0.00	$997.57	$46.01	4.8%
Large	34,240	$27.00	$1,951.65	$1,114.07	$0.00	$3,092.72	$120.52	4.1%
XLg	56,800	$27.00	$3,237.54	$1,848.10	$0.00	$5,112.64	$192.34	3.9%
AnnAvg	14,343	$27.00	$817.55	$466.68	$0.00	$1,311.23	$57.17	4.6%
SGSAvg	12,251	$27.00	$698.29	$398.61	$0.00	$1,123.90	$50.51	4.7%

EXHIBIT HS-8

Municipal Water Pumping Rate GS-43

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		$15.50	$0.06800	$0.035111	$0.00682	
Xsm	160	$15.50	$10.85	$5.60	$1.09	$33.04
Small	2,766	$15.50	$188.05	$97.10	$18.86	$319.51
Medium	17,280	$15.50	$1,175.04	$606.72	$117.85	$1,915.11
Large	46,160	$15.50	$3,138.88	$1,620.72	$314.81	$5,089.91
XLg	83,200	$15.50	$5,657.60	$2,921.24	$567.42	$9,161.76
AnnAvg	14,343	$15.50	$975.34	$503.60	$97.82	$1,592.26
SGSAvg	17,209	$15.50	$1,170.21	$604.23	$117.37	$1,907.31

BILL IMPACTS PROPOSED RATES

	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		$27.00	$0.07330	$0.035868	$0.00000			
Xsm	160	$27.00	$11.69	$5.72	$0.00	$44.41	$11.37	34.4%
Small	2,766	$27.00	$202.71	$99.19	$0.00	$328.90	$9.39	2.9%
Medium	17,280	$27.00	$1,266.61	$619.80	$0.00	$1,913.41	-$1.70	-0.1%
Large	46,160	$27.00	$3,383.48	$1,655.67	$0.00	$5,066.15	-$23.76	-0.5%
XLg	83,200	$27.00	$6,098.48	$2,984.22	$0.00	$9,109.70	-$52.06	-0.6%
AnnAvg	14,343	$27.00	$1,051.34	$514.46	$0.00	$1,592.80	$0.54	0.0%
SGSAvg	17,209	$27.00	$1,261.40	$617.25	$0.00	$1,905.65	-$1.66	-0.1%

EXHIBIT HS-8

Municipal Interruptible Water Pumping Rate GS-43

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		$15.50	$0.02700	$0.028420	$0.00682	
Xsm	90	$15.50	$2.43	$2.56	$0.61	$21.10
Small	1,440	$15.50	$38.88	$40.92	$9.82	$105.12
Medium	10,840	$15.50	$292.68	$308.07	$73.93	$690.18
Large	34,240	$15.50	$924.48	$973.10	$233.52	$2,146.60
XLg	56,800	$15.50	$1,533.60	$1,614.26	$387.38	$3,550.74
AnnAvg	14,343	$15.50	$387.27	$407.63	$97.82	$908.22
SGSAvg	12,251	$15.50	$330.78	$348.17	$83.55	$778.00

BILL IMPACTS PROPOSED RATES

	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		$27.00	$0.03600	$0.029400	$0.00000			
Xsm	90	$27.00	$3.24	$2.65	$0.00	$32.89	$11.79	55.9%
Small	1,440	$27.00	$51.84	$42.34	$0.00	$121.18	$16.06	15.3%
Medium	10,840	$27.00	$390.24	$318.70	$0.00	$735.94	$45.76	6.6%
Large	34,240	$27.00	$1,232.64	$1,006.66	$0.00	$2,266.30	$119.70	5.6%
XLg	56,800	$27.00	$2,044.80	$1,669.92	$0.00	$3,741.72	$190.98	5.4%
AnnAvg	14,343	$27.00	$516.35	$421.69	$0.00	$965.04	$56.82	6.3%
SGSAvg	12,251	$27.00	$441.03	$360.18	$0.00	$828.21	$50.21	6.5%

EXHIBIT HS-8

Municipal Interruptible Water Pumping Rate GS-43

SUMMER

	BILL IMPACTS CURRENT RATES					
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		$15.50	$0.04200	$0.031310	$0.00682	
Xsm	160	$15.50	$6.70	$4.99	$1.09	$28.28
Small	2,766	$15.50	$116.15	$86.59	$18.86	$237.10
Medium	17,280	$15.50	$725.76	$541.04	$117.85	$1,400.15
Large	46,160	$15.50	$1,938.72	$1,445.27	$314.81	$3,714.30
XLg	83,200	$15.50	$3,494.40	$2,604.99	$567.42	$6,682.31
AnnAvg	14,343	$15.50	$602.41	$449.08	$97.82	$1,164.81
SGSAvg	17,209	$15.50	$722.78	$538.81	$117.37	$1,394.46

	BILL IMPACTS PROPOSED RATES							
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill		
		$27.00	$0.04730	$0.032100	$0.00000			
							$ Change	% Change
Xsm	160	$27.00	$7.54	$5.12	$0.00	$39.66	$11.38	40.2%
Small	2,766	$27.00	$130.81	$88.77	$0.00	$246.58	$9.48	4.0%
Medium	17,280	$27.00	$817.34	$554.69	$0.00	$1,399.03	-$1.12	-0.1%
Large	46,160	$27.00	$2,183.37	$1,481.74	$0.00	$3,692.11	-$22.19	-0.6%
XLg	83,200	$27.00	$3,935.36	$2,670.72	$0.00	$6,633.08	-$49.23	-0.7%
AnnAvg	14,343	$27.00	$678.43	$460.42	$0.00	$1,165.85	$1.04	0.1%
SGSAvg	17,209	$27.00	$813.99	$552.41	$0.00	$1,393.40	-$1.06	-0.1%

EXHIBIT HS-8

SMALL GENERAL SERVICE TIME OF USE RATE GS-76

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
On-Peak	0.24			$17.50	$0.08140	$0.08140	$0.032893	$0.00682	
Off-Peak	0.76				$0.06490	$0.06490	$0.027092		
Xsm	190	190	0	$17.50	$13.07	$0.00	$5.41	$1.30	$37.28
Small	687	500	187	$17.50	$34.40	$12.87	$19.55	$4.69	$89.01
Medium	1,744	500	1,244	$17.50	$34.40	$85.59	$49.64	$11.89	$199.02
Large	3,680	500	3,180	$17.50	$34.40	$218.78	$104.74	$25.10	$400.52
XLg	5,157	500	4,657	$17.50	$34.40	$320.40	$146.78	$35.17	$554.25
AnnAvg	1,568	500	1,068	$17.50	$34.40	$73.48	$44.63	$10.69	$180.70
SGSAvg	1,340	500	840	$17.50	$34.40	$57.79	$38.14	$9.14	$156.97

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
On-Peak	0.24			$27.00	$0.05690	$0.07790	$0.033893	$0.00000			
Off-Peak	0.76				$0.05690	$0.07790	$0.028092			$ Change	% Change
Xsm	190	190	0	$27.00	$10.81	$0.00	$5.60	$0.00	$43.41	$6.13	16.4%
Small	687	500	187	$27.00	$28.45	$14.57	$20.24	$0.00	$90.26	$1.25	1.4%
Medium	1,744	500	1,244	$27.00	$28.45	$96.91	$51.38	$0.00	$203.74	$4.72	2.4%
Large	3,680	500	3,180	$27.00	$28.45	$247.72	$108.42	$0.00	$411.59	$11.07	2.8%
XLg	5,157	500	4,657	$27.00	$28.45	$362.78	$151.94	$0.00	$570.17	$15.92	2.9%
AnnAvg	1,568	500	1,068	$27.00	$28.45	$83.20	$46.20	$0.00	$184.85	$4.15	2.3%
SGSAvg	1,340	500	840	$27.00	$28.45	$65.44	$39.48	$0.00	$160.37	$3.40	2.2%

EXHIBIT HS-8

SMALL GENERAL SERVICE TIME OF USE RATE GS-76

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500	$17.50	500	>500			
On-Peak	0.20				$0.09910	$0.09910	$0.050669	$0.00682	
Off-Peak	0.80				$0.08490	$0.08490	$0.026679		
Xsm	216	216	0	$17.50	$18.96	$0.00	$6.81	$1.47	$44.74
Small	882	500	382	$17.50	$43.89	$33.53	$27.82	$6.02	$128.76
Medium	2,354	500	1,854	$17.50	$43.89	$162.75	$74.26	$16.05	$314.45
Large	4,820	500	4,320	$17.50	$43.89	$379.22	$152.06	$32.87	$625.54
XLg	6,690	500	6,190	$17.50	$43.89	$543.37	$211.05	$45.63	$861.44
AnnAvg	1,568	500	1,068	$17.50	$43.89	$93.75	$49.47	$10.69	$215.30
SGSAvg	1,886	500	1,386	$17.50	$43.89	$121.63	$59.48	$12.86	$255.36

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
On-Peak	0.20			$27.00	$0.07690	$0.09690	$0.051660	$0.00000			
Off-Peak	0.80				$0.07690	$0.09690	$0.026750			$ Change	% Change
Xsm	216	216	0	$27.00	$16.61	$0.00	$6.87	$0.00	$50.48	$5.74	12.8%
Small	882	500	382	$27.00	$38.45	$37.02	$28.05	$0.00	$130.52	$1.76	1.4%
Medium	2,354	500	1,854	$27.00	$38.45	$179.65	$74.87	$0.00	$319.97	$5.52	1.8%
Large	4,820	500	4,320	$27.00	$38.45	$418.60	$153.30	$0.00	$637.35	$11.81	1.9%
XLg	6,690	500	6,190	$27.00	$38.45	$599.80	$212.77	$0.00	$878.02	$16.58	1.9%
AnnAvg	1,568	500	1,068	$27.00	$38.45	$103.49	$49.87	$0.00	$218.81	$3.51	1.6%
SGSAvg	1,886	500	1,386	$27.00	$38.45	$134.26	$59.97	$0.00	$259.68	$4.32	1.7%

EXHIBIT HS-8

SMALL GENERAL SERVICE DEMAND TIME OF USE

WINTER

BILL IMPACTS CURRENT GS-76 RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill
			500	>500				$17.50	500	>500					
On-Peak		0.24							$0.08140	$0.08140			$0.032893	$0.00682	
Off-Peak		0.76							$0.06490	$0.06490			$0.027092		
Xsm	0.21	190	190	0	1.2			$17.50	$13.07	$0.00			$5.41	$1.30	$37.28
Small	0.29	687	500	187	3.2			$17.50	$34.40	$12.87			$19.55	$4.69	$89.01
Medium	0.37	1,744	500	1,244	6.5			$17.50	$34.40	$85.59			$49.64	$11.89	$199.02
Large	0.45	3,680	500	3,180	11.3			$17.50	$34.40	$218.78			$104.74	$25.10	$400.52
XLg	0.49	5,157	500	4,657	14.5			$17.50	$34.40	$320.40			$146.78	$35.17	$554.25
AnnAvg	0.36	1,568	500	1,068	6.0			$17.50	$34.40	$73.48			$44.63	$10.69	$180.70
SGSAvg	0.35	1,340	500	840	5.3			$17.50	$34.40	$57.79			$38.14	$9.14	$156.97

BILL IMPACTS PROPOSED RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill		
			500	>500		7.0	> 7.0		500	>500	7.0	> 7.0					
On-Peak		0.24						$27.00	$0.04777	$0.04777	$9.60	$13.75	$0.033893	$0.00000			
Off-Peak		0.76							$0.04777	$0.04777			$0.028092			$ Change	% Change
Xsm	0.21	190	190	0	1.2	1.2	0.0	$27.00	$9.08	$0.00	$11.90	$0.00	$5.60	$0.00	$53.58	$16.30	43.7%
Small	0.29	687	500	187	3.2	3.2	0.0	$27.00	$23.89	$8.93	$31.01	$0.00	$20.24	$0.00	$111.07	$22.06	24.8%
Medium	0.37	1,744	500	1,244	6.5	6.5	0.0	$27.00	$23.89	$59.43	$62.11	$0.00	$51.38	$0.00	$223.81	$24.79	12.5%
Large	0.45	3,680	500	3,180	11.3	7.0	4.3	$27.00	$23.89	$151.91	$67.20	$58.85	$108.42	$0.00	$437.27	$36.75	9.2%
XLg	0.49	5,157	500	4,657	14.5	7.0	7.5	$27.00	$23.89	$222.46	$67.20	$103.26	$151.94	$0.00	$595.75	$41.50	7.5%
AnnAvg	0.36	1,568	500	1,068	6.0	6.0	0.0	$27.00	$23.89	$51.02	$57.41	$0.00	$46.20	$0.00	$205.52	$24.82	13.7%
SGSAvg	0.35	1,340	500	840	5.3	5.3	0.0	$27.00	$23.89	$40.13	$51.07	$0.00	$39.48	$0.00	$181.57	$24.60	15.7%

EXHIBIT HS-8

SMALL GENERAL SERVICE DEMAND TIME OF USE

SUMMER

BILL IMPACTS CURRENT GS-76 RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill
			500	>500				$17.50	500	>500					
On-Peak		0.20							$0.09910	$0.09910			$0.050669	$0.00682	
Off-Peak		0.80							$0.08490	$0.08490			$0.026679		
Xsm	0.22	216	216	0	1.4			$17.50	$18.96	$0.00			$6.81	$1.47	$44.74
Small	0.31	882	500	382	3.9			$17.50	$43.89	$33.53			$27.82	$6.02	$128.76
Medium	0.40	2,354	500	1,854	8.1			$17.50	$43.89	$162.75			$74.26	$16.05	$314.45
Large	0.48	4,820	500	4,320	13.8			$17.50	$43.89	$379.22			$152.06	$32.87	$625.54
XLg	0.52	6,690	500	6,190	17.6			$17.50	$43.89	$543.37			$211.05	$45.63	$861.44
AnnAvg	0.36	1,568	500	1,068	6.0			$17.50	$43.89	$93.75			$49.47	$10.69	$215.30
SGSAvg	0.38	1,886	500	1,386	6.9			$17.50	$43.89	$121.63			$59.48	$12.86	$255.36

BILL IMPACTS PROPOSED RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill		
			500	>500		7.0	> 7.0		500	>500	7.0	> 7.0					
On-Peak		0.20						$27.00	$0.05777	$0.05777	$9.60	$13.75	$0.05166	$0.00000			
Off-Peak		0.80							$0.05777	$0.05777			$0.026750			$ Change	% Change
Xsm	0.22	216	216	0	1.4	1.4	0.0	$27.00	$12.48	$0.00	$13.06	$0.00	$6.87	$0.00	$59.41	$14.67	32.8%
Small	0.31	882	500	382	3.9	3.9	0.0	$27.00	$28.89	$22.07	$37.34	$0.00	$28.05	$0.00	$143.35	$14.59	11.3%
Medium	0.40	2,354	500	1,854	8.1	7.0	1.1	$27.00	$28.89	$107.11	$67.20	$14.99	$74.87	$0.00	$320.06	$5.61	1.8%
Large	0.48	4,820	500	4,320	13.8	7.0	6.8	$27.00	$28.89	$249.57	$67.20	$93.36	$153.30	$0.00	$619.32	-$6.22	-1.0%
XLg	0.52	6,690	500	6,190	17.6	7.0	10.6	$27.00	$28.89	$357.60	$67.20	$145.89	$212.77	$0.00	$839.35	-$22.09	-2.6%
AnnAvg	0.36	1,568	500	1,068	6.0	6.0	0.0	$27.00	$28.89	$61.70	$57.41	$0.00	$49.87	$0.00	$224.87	$9.57	4.4%
SGSAvg	0.38	1,886	500	1,386	6.9	6.9	0.0	$27.00	$28.89	$80.05	$65.86	$0.00	$59.97	$0.00	$261.77	$6.41	2.5%

EXHIBIT HS-8

Medium General Service RATE MGS

WINTER

	BILL IMPACTS CURRENT RATES (GS-10)								
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.05700	$0.07900	$0.031532	$0.00682	
Xsm	9,000	500	8,500	$15.50	$28.50	$671.50	$283.79	$61.38	$1,060.67
Small	14,000	500	13,500	$15.50	$28.50	$1,066.50	$441.45	$95.48	$1,647.43
Medium	23,000	500	22,500	$15.50	$28.50	$1,777.50	$725.24	$156.86	$2,703.60
Large	37,000	500	36,500	$15.50	$28.50	$2,883.50	$1,166.68	$252.34	$4,346.52
XLg	45,000	500	44,500	$15.50	$28.50	$3,515.50	$1,418.94	$306.90	$5,285.34
AnnAvg	20,468	500	19,968	$15.50	$28.50	$1,577.50	$645.41	$139.59	$2,406.50
MGSAvg	17,563	500	17,063	$15.50	$28.50	$1,347.99	$553.80	$119.78	$2,065.57

	BILL IMPACTS PROPOSED RATES (MGS)									
	kW	kWh	Basic Service Charge	kW Charge	Delivery Charge kWh	Base Fuel	PPFAC	Net Bill		
			$40.00	$3.65	$0.06990	$0.032537	$0.00000			
Load Factor	35%								$ Change	% Change
Xsm	34	9,000	$40.00	$125.21	$629.09	$292.83	$0.00	$1,087.13	$26.46	2.5%
Small	53	14,000	$40.00	$194.78	$978.59	$455.52	$0.00	$1,668.89	$21.46	1.3%
Medium	88	23,000	$40.00	$319.99	$1,607.68	$748.35	$0.00	$2,716.02	$12.42	0.5%
Large	141	37,000	$40.00	$514.77	$2,586.26	$1,203.87	$0.00	$4,344.90	-$1.62	0.0%
XLg	172	45,000	$40.00	$626.07	$3,145.46	$1,464.17	$0.00	$5,275.70	-$9.64	-0.2%
AnnAvg	78	20,468	$40.00	$284.77	$1,430.71	$665.98	$0.00	$2,421.46	$14.96	0.6%
MGSAvg	67	17,563	$40.00	$244.35	$1,227.65	$571.45	$0.00	$2,083.45	$17.88	0.9%

EXHIBIT HS-8

Medium General Service RATE MGS

SUMMER

	BILL IMPACTS CURRENT RATES (GS-10)								
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.07700	$0.09780	$0.035111	$0.00682	
Xsm	14,000	500	13,500	$15.50	$38.50	$1,320.30	$491.55	$95.48	$1,961.33
Small	19,000	500	18,500	$15.50	$38.50	$1,809.30	$667.11	$129.58	$2,659.99
Medium	32,000	500	31,500	$15.50	$38.50	$3,080.70	$1,123.55	$218.24	$4,476.49
Large	50,000	500	49,500	$15.50	$38.50	$4,841.10	$1,755.55	$341.00	$6,991.65
XLg	62,000	500	61,500	$15.50	$38.50	$6,014.70	$2,176.88	$422.84	$8,668.42
AnnAvg	20,468	500	19,968	$15.50	$38.50	$1,952.90	$718.66	$139.59	$2,865.15
MGSAvg	24,544	500	24,044	$15.50	$38.50	$2,351.53	$861.78	$167.39	$3,434.70

	BILL IMPACTS PROPOSED RATES (MGS)									
	kW	kWh	Basic Service Charge	kW Charge	Delivery Charge kWh	Base Fuel	PPFAC	Net Bill		
			$40.00	$6.75	$0.08290	$0.035868	$0.00000			
Load Factor	35%								$ Change	% Change
Xsm	53	14,000	$40.00	$360.21	$1,160.59	$502.15	$0.00	$2,062.95	$101.62	5.2%
Small	72	19,000	$40.00	$488.85	$1,575.08	$681.49	$0.00	$2,785.42	$125.43	4.7%
Medium	122	32,000	$40.00	$823.33	$2,652.77	$1,147.78	$0.00	$4,663.88	$187.39	4.2%
Large	191	50,000	$40.00	$1,286.45	$4,144.95	$1,793.40	$0.00	$7,264.80	$273.15	3.9%
XLg	236	62,000	$40.00	$1,595.20	$5,139.74	$2,223.82	$0.00	$8,998.76	$330.34	3.8%
AnnAvg	78	20,468	$40.00	$526.63	$1,696.80	$734.16	$0.00	$2,997.59	$132.44	4.6%
MGSAvg	94	24,544	$40.00	$631.50	$2,034.70	$880.36	$0.00	$3,586.56	$151.86	4.4%

EXHIBIT HS-8

MEDIUM GENERAL SERVICE TIME OF USE

Winter

	BILL IMPACTS CURRENT RATES (GS-76)							
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		500	>500					
On-Peak	0.24			$17.50	$0.08140	$0.032893	$0.00682	
Off-Peak	0.76				$0.06490	$0.027092		
Xsm	13,000	500	12,500	$17.50	$896.00	$370.58	$88.66	$1,372.74
Small	21,000	500	20,500	$17.50	$1,447.38	$598.63	$143.22	$2,206.73
Medium	29,000	500	28,500	$17.50	$1,998.77	$826.69	$197.78	$3,040.74
Large	39,000	500	38,500	$17.50	$2,688.00	$1,111.75	$265.98	$4,083.23
XLg	48,000	500	47,500	$17.50	$3,308.30	$1,368.31	$327.36	$5,021.47
AnnAvg	25,332	500	24,832	$17.50	$1,745.94	$722.12	$172.76	$2,658.32
MGSAvg	17,563	500	17,063	$17.50	$1,210.51	$500.66	$119.78	$1,848.45

	BILL IMPACTS PROPOSED RATES (MGS TOU)									
	kW	kWh	Basic Service Charge	Demand Charge	Delivery	Base Fuel	PPFAC	Net Bill		
Load Factor	63%									
On-Peak		0.24	$40.00	$3.35	$0.10950	$0.033893	$0.00000			
Off-Peak		0.76			$0.06690	$0.028092			$ Change	% Change
Xsm	28	13,000	$40.00	$92.59	$1,004.71	$383.58	$0.00	$1,520.88	$148.14	10.8%
Small	45	21,000	$40.00	$149.57	$1,623.00	$619.63	$0.00	$2,432.20	$225.47	10.2%
Medium	62	29,000	$40.00	$206.55	$2,241.28	$855.69	$0.00	$3,343.52	$302.78	10.0%
Large	83	39,000	$40.00	$277.77	$3,014.14	$1,150.75	$0.00	$4,482.66	$399.43	9.8%
XLg	102	48,000	$40.00	$341.87	$3,709.71	$1,416.31	$0.00	$5,507.89	$486.42	9.7%
AnnAvg	54	25,332	$40.00	$180.42	$1,957.78	$747.45	$0.00	$2,925.65	$267.33	10.1%
MGSAvg	37	17,563	$40.00	$125.09	$1,357.38	$518.23	$0.00	$2,040.70	$192.25	10.4%

EXHIBIT HS-8

MEDIUM GENERAL SERVICE TIME OF USE

Summer

	BILL IMPACTS CURRENT RATES (GS-76)							
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		500	>500					
On-Peak	0.20			$17.50	$0.09910	$0.050669	$0.00682	
Off-Peak	0.80				$0.08490	$0.026679		
Xsm	18,000	500	17,500	$17.50	$1,580.16	$568.01	$122.76	$2,288.43
Small	27,000	500	26,500	$17.50	$2,370.24	$852.01	$184.14	$3,423.89
Medium	37,000	500	36,500	$17.50	$3,248.11	$1,167.57	$252.34	$4,685.52
Large	50,000	500	49,500	$17.50	$4,389.34	$1,577.80	$341.00	$6,325.64
XLg	65,000	500	64,500	$17.50	$5,706.14	$2,051.14	$443.30	$8,218.08
AnnAvg	25,332	500	24,832	$17.50	$2,223.79	$799.37	$172.76	$3,213.42
MGSAvg	24,544	500	24,044	$17.50	$2,154.67	$774.52	$167.39	$3,114.08

	BILL IMPACTS PROPOSED RATES (MGS TOU)									
	kW	kWh	Basic Service Charge	Demand Charge	Delivery	Base Fuel	PPFAC	Net Bill		
Load Factor	63%									
On-Peak		0.20	$40.00	$7.75	$0.10950	$0.051660	$0.00000			
Off-Peak		0.80			$0.06690	$0.026750			$ Change	% Change
Xsm	38	18,000	$40.00	$296.59	$1,360.07	$572.65	$0.00	$2,269.31	-$19.12	-0.8%
Small	57	27,000	$40.00	$444.88	$2,040.10	$858.98	$0.00	$3,383.96	-$39.93	-1.2%
Medium	79	37,000	$40.00	$609.65	$2,795.69	$1,177.12	$0.00	$4,622.46	-$63.06	-1.3%
Large	106	50,000	$40.00	$823.86	$3,777.96	$1,590.70	$0.00	$6,232.52	-$93.12	-1.5%
XLg	138	65,000	$40.00	$1,071.01	$4,911.35	$2,067.91	$0.00	$8,090.27	-$127.81	-1.6%
AnnAvg	54	25,332	$40.00	$417.39	$1,914.05	$805.90	$0.00	$3,177.34	-$36.08	-1.1%
MGSAvg	52	24,544	$40.00	$404.42	$1,854.55	$780.85	$0.00	$3,079.82	-$34.26	-1.1%

EXHIBIT HS-8

Large General Service Rate LGS-13

WINTER

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill
				$775.00	$15.25	$0.01340	$0.031532	$0.00682	
Xsm	0.55	200	58,000	$775.00	$3,050.00	$777.20	$1,828.86	$395.56	$6,826.62
Small	0.55	223	91,360	$775.00	$3,404.79	$1,224.22	$2,880.76	$623.08	$8,907.85
Medium	0.55	427	174,840	$775.00	$6,515.91	$2,342.86	$5,513.05	$1,192.41	$16,339.23
Large	0.55	725	296,700	$775.00	$11,057.37	$3,975.78	$9,355.54	$2,023.49	$27,187.18
XLg	0.55	1088	445,200	$775.00	$16,591.64	$5,965.68	$14,038.05	$3,036.26	$40,406.63
AnnAvg	0.55	395	161,792	$775.00	$6,029.62	$2,168.01	$5,101.61	$1,103.42	$15,177.66
LGSAvg	0.55	366	149,663	$775.00	$5,577.62	$2,005.48	$4,719.17	$1,020.70	$14,097.97

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$950.00	$17.55	$0.01430	$0.032537	$0.00000			
Xsm	0.55	200	58,000	$950.00	$3,510.00	$829.40	$1,887.15	$0.00	$7,176.55	$349.93	5.1%
Small	0.55	223	91,360	$950.00	$3,918.30	$1,306.45	$2,972.58	$0.00	$9,147.33	$239.48	2.7%
Medium	0.55	427	174,840	$950.00	$7,498.64	$2,500.21	$5,688.77	$0.00	$16,637.62	$298.39	1.8%
Large	0.55	725	296,700	$950.00	$12,725.04	$4,242.81	$9,653.73	$0.00	$27,571.58	$384.40	1.4%
XLg	0.55	1,088	445,200	$950.00	$19,093.99	$6,366.36	$14,485.47	$0.00	$40,895.82	$489.19	1.2%
AnnAvg	0.55	395	161,792	$950.00	$6,939.01	$2,313.62	$5,264.21	$0.00	$15,466.84	$289.18	1.9%
LGSAvg	0.55	366	149,663	$950.00	$6,418.83	$2,140.18	$4,869.59	$0.00	$14,378.60	$280.63	2.0%

EXHIBIT HS-8

Large General Service Rate LGS-13

SUMMER

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill
				$775.00	$15.25	$0.01920	$0.035111	$0.00682	
Xsm	0.55	200	72,960	$775.00	$3,050.00	$1,400.83	$2,561.70	$497.59	$8,285.12
Small	0.55	282	115,584	$775.00	$4,307.57	$2,219.21	$4,058.27	$788.28	$12,148.33
Medium	0.55	521	213,300	$775.00	$7,949.23	$4,095.36	$7,489.18	$1,454.71	$21,763.48
Large	0.55	815	333,600	$775.00	$12,432.55	$6,405.12	$11,713.03	$2,275.15	$33,600.85
XLg	0.55	1230	503,200	$775.00	$18,753.18	$9,661.44	$17,667.86	$3,431.82	$50,289.30
AnnAvg	0.55	395	161,792	$775.00	$6,029.62	$3,106.40	$5,680.66	$1,103.42	$16,695.10
LGSAvg	0.55	437	178,619	$775.00	$6,656.74	$3,429.48	$6,271.49	$1,218.18	$18,350.89

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$950.00	$17.55	$0.01850	$0.035868	$0.00000			
Xsm	0.55	200	72,960	$950.00	$3,510.00	$1,349.76	$2,616.93	$0.00	$8,426.69	$141.57	1.7%
Small	0.55	282	115,584	$950.00	$4,957.23	$2,138.30	$4,145.77	$0.00	$12,191.30	$42.97	0.4%
Medium	0.55	521	213,300	$950.00	$9,148.13	$3,946.05	$7,650.64	$0.00	$21,694.82	-$68.66	-0.3%
Large	0.55	815	333,600	$950.00	$14,307.62	$6,171.60	$11,965.56	$0.00	$33,394.78	-$206.07	-0.6%
XLg	0.55	1,230	503,200	$950.00	$21,581.52	$9,309.20	$18,048.78	$0.00	$49,889.50	-$399.80	-0.8%
AnnAvg	0.55	395	161,792	$950.00	$6,939.01	$2,993.14	$5,803.14	$0.00	$16,685.29	-$9.81	-0.1%
LGSAvg	0.55	437	178,619	$950.00	$7,660.70	$3,304.45	$6,406.70	$0.00	$18,321.85	-$29.04	-0.2%

EXHIBIT HS-8

Large General Service Time of Use Rate LGS-85

WINTER

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill
	On-Peak		24.3%	$950.00	$11.59	$0.00300	$0.032893	$0.00682	
	Off-Peak		75.7%		$9.10	$0.00050	$0.027092		
Xsm	0.58	288	124,480	$950.00	$5,443.40	$137.85	$3,547.85	$848.95	$10,928.05
Small	0.58	390	168,111	$950.00	$7,351.33	$186.16	$4,791.38	$1,146.51	$14,425.38
Medium	0.58	476	205,552	$950.00	$8,988.61	$227.63	$5,858.52	$1,401.86	$17,426.62
Large	0.58	621	267,929	$950.00	$11,716.31	$296.70	$7,636.35	$1,827.28	$22,426.64
XLg	0.58	827	356,983	$950.00	$15,610.54	$395.32	$10,174.50	$2,434.62	$29,564.98
AnnAvg	0.58	448	193,169	$950.00	$8,447.12	$213.91	$5,505.59	$1,317.41	$16,434.03
LGSAvg	0.58	347	149,663	$950.00	$6,544.64	$165.74	$4,265.60	$1,020.70	$12,946.68

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill		
	On-Peak		24.3%	$950.00	$18.50	$0.00710	$0.033893	$0.00000			
	Off-Peak		75.7%			$0.00125	$0.028092			$ Change	% Change
Xsm	0.58	288	124,480	$950.00	$5,336.67	$332.52	$3,672.33	$0.00	$10,291.52	-$636.53	-5.8%
Small	0.58	390	168,111	$950.00	$7,207.18	$449.07	$4,959.49	$0.00	$13,565.74	-$859.64	-6.0%
Medium	0.58	476	205,552	$950.00	$8,812.37	$549.09	$6,064.07	$0.00	$16,375.53	-$1,051.09	-6.0%
Large	0.58	621	267,929	$950.00	$11,486.57	$715.72	$7,904.28	$0.00	$21,056.57	-$1,370.07	-6.1%
XLg	0.58	827	356,983	$950.00	$15,304.45	$953.60	$10,531.48	$0.00	$27,739.53	-$1,825.45	-6.2%
AnnAvg	0.58	448	193,169	$950.00	$8,281.49	$516.01	$5,698.76	$0.00	$15,446.26	-$987.77	-6.0%
LGSAvg	0.58	347	149,663	$950.00	$6,416.31	$399.79	$4,415.27	$0.00	$12,181.37	-$765.31	-5.9%

Tucson Electric Power Company
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending June 30, 2015

Large General Service Time of Use Rate LGS-85

SUMMER

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill
	On-Peak		19.7%	$950.00	$14.55	$0.00860	$0.050669	$0.00682	
	Off-Peak		80.3%		$10.92	$0.00600	$0.026679		
Xsm	0.58	317	136,680	$950.00	$7,375.63	$890.15	$4,293.00	$932.16	$14,440.94
Small	0.58	436	188,009	$950.00	$10,145.48	$1,224.44	$5,905.20	$1,282.22	$19,507.34
Medium	0.58	536	231,233	$950.00	$12,477.97	$1,505.94	$7,262.82	$1,577.01	$23,773.74
Large	0.58	736	317,688	$950.00	$17,143.31	$2,068.99	$9,978.30	$2,166.63	$32,307.23
XLg	0.58	976	420,961	$950.00	$22,716.21	$2,741.57	$13,222.01	$2,870.95	$42,500.74
AnnAvg	0.58	448	193,169	$950.00	$10,423.93	$1,258.04	$6,067.27	$1,317.41	$20,016.65
LGSAvg	0.58	414	178,619	$950.00	$9,638.76	$1,163.28	$5,610.26	$1,218.18	$18,580.48

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill	$ Change	% Change
	On-Peak		19.7%	$950.00	$22.15	$0.01854	$0.051660	$0.00000			
	Off-Peak		80.3%			$0.01270	$0.026750				
Xsm	0.58	317	136,680	$950.00	$7,015.81	$1,893.22	$4,327.50	$0.00	$14,186.53	-$254.41	-1.8%
Small	0.58	436	188,009	$950.00	$9,650.54	$2,604.20	$5,952.65	$0.00	$19,157.39	-$349.95	-1.8%
Medium	0.58	536	231,233	$950.00	$11,869.23	$3,202.92	$7,321.19	$0.00	$23,343.34	-$430.40	-1.8%
Large	0.58	736	317,688	$950.00	$16,306.98	$4,400.45	$10,058.48	$0.00	$31,715.91	-$591.32	-1.8%
XLg	0.58	976	420,961	$950.00	$21,608.00	$5,830.93	$13,328.26	$0.00	$41,717.19	-$783.55	-1.8%
AnnAvg	0.58	448	193,169	$950.00	$9,915.41	$2,675.68	$6,116.03	$0.00	$19,657.12	-$359.53	-1.8%
LGSAvg	0.58	414	178,619	$950.00	$9,168.54	$2,474.13	$5,655.34	$0.00	$18,248.01	-$332.47	-1.8%

EXHIBIT HS-8

Large Power Service Rate LPS-90

WINTER

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill
	On-Peak		23.1%	$2,000.00	$15.49	$0.00750	$0.029581	$0.00682	
	Off-Peak		76.9%			$0.00710	$0.024352		
Xsm	0.80	4,460	2,654,563	$2,000.00	$69,084.65	$19,092.82	$67,852.15	$18,104.12	$176,133.74
Small	0.80	7,130	4,243,957	$2,000.00	$110,448.41	$30,524.46	$108,477.97	$28,943.79	$280,394.63
Medium	0.80	13,369	7,957,222	$2,000.00	$207,085.63	$57,231.93	$203,391.15	$54,268.25	$523,976.96
Large	0.80	16,093	9,578,605	$2,000.00	$249,281.91	$68,893.65	$244,834.63	$65,326.09	$630,336.28
XLg	0.80	17,404	10,359,070	$2,000.00	$269,593.40	$74,507.11	$264,783.76	$70,648.86	$681,533.13
AnnAvg	0.80	9,398	5,593,406	$2,000.00	$145,567.63	$40,230.30	$142,970.65	$38,147.03	$368,915.61
LPSAvg	0.80	8,725	5,193,148	$2,000.00	$135,150.99	$37,351.47	$132,739.84	$35,417.27	$342,659.57

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill		
	On-Peak		23.1%	$10,000.00	$17.06	$0.00740	$0.032198	$0.00000			
	Off-Peak		76.9%			$0.00740	$0.026687			$ Change	% Change
Xsm	0.80	4,460	2,654,563	$10,000.00	$76,086.77	$19,643.77	$74,223.57	$0.00	$179,954.11	$3,820.37	2.2%
Small	0.80	7,130	4,243,957	$10,000.00	$121,642.99	$31,405.28	$118,664.22	$0.00	$281,712.49	$1,317.86	0.5%
Medium	0.80	13,369	7,957,222	$10,000.00	$228,074.95	$58,883.44	$222,489.90	$0.00	$519,448.29	-$4,528.67	-0.9%
Large	0.80	16,093	9,578,605	$10,000.00	$274,548.05	$70,881.68	$267,824.99	$0.00	$623,254.72	-$7,081.56	-1.1%
XLg	0.80	17,404	10,359,070	$10,000.00	$296,918.24	$76,657.12	$289,647.38	$0.00	$673,222.74	-$8,310.39	-1.2%
AnnAvg	0.80	9,398	5,593,406	$10,000.00	$160,321.74	$41,391.20	$156,395.82	$0.00	$368,108.76	-$806.85	-0.2%
LPSAvg	0.80	8,725	5,193,148	$10,000.00	$148,849.31	$38,429.30	$145,204.33	$0.00	$342,482.94	-$176.63	-0.1%

EXHIBIT HS-8

Large Power Service Rate LPS-90

Summer

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill
	On-Peak		17.0%	$2,000.00	$20.49	$0.00690	$0.045568	$0.00682	
	Off-Peak		83.0%			$0.00650	$0.023985		
Xsm	0.80	4527	2,694,604	$2,000.00	$92,762.83	$17,698.42	$74,530.92	$18,377.20	$205,369.37
Small	0.80	8371	4,982,527	$2,000.00	$171,525.50	$32,725.72	$137,813.33	$33,980.83	$378,045.38
Medium	0.80	14825	8,823,900	$2,000.00	$303,766.32	$57,956.23	$244,063.10	$60,179.00	$667,964.65
Large	0.80	19858	11,819,577	$2,000.00	$406,893.70	$77,632.12	$326,921.50	$80,609.52	$894,056.84
XLg	0.80	21021	12,511,438	$2,000.00	$430,711.30	$82,176.33	$346,057.91	$85,328.01	$946,273.55
AnnAvg	0.80	9398	5,593,406	$2,000.00	$192,555.25	$36,738.03	$154,709.82	$38,147.03	$424,150.13
LPSAvg	0.80	10375	6,174,912	$2,000.00	$212,573.82	$40,557.42	$170,793.88	$42,112.90	$468,038.02

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill	$ Change	% Change
	On-Peak		17.0%	$10,000.00	$22.60	$0.00740	$0.049077	$0.00000			
	Off-Peak		83.0%			$0.00740	$0.025413				
Xsm	0.80	4,527	2,694,604	$10,000.00	$102,315.27	$19,940.07	$79,333.44	$0.00	$211,588.78	$6,219.41	3.0%
Small	0.80	8,371	4,982,527	$10,000.00	$189,188.69	$36,870.70	$146,693.55	$0.00	$382,752.94	$4,707.56	1.2%
Medium	0.80	14,825	8,823,900	$10,000.00	$335,047.28	$65,296.86	$259,789.70	$0.00	$670,133.84	$2,169.19	0.3%
Large	0.80	19,858	11,819,577	$10,000.00	$448,794.42	$87,464.87	$347,987.21	$0.00	$894,246.50	$189.66	0.0%
XLg	0.80	21,021	12,511,438	$10,000.00	$475,064.68	$92,584.64	$368,356.70	$0.00	$946,006.02	-$267.53	0.0%
AnnAvg	0.80	9,398	5,593,406	$10,000.00	$212,384.02	$41,391.20	$164,678.79	$0.00	$428,454.01	$4,303.88	1.0%
LPSAvg	0.80	10,375	6,174,912	$10,000.00	$234,464.05	$45,694.35	$181,799.25	$0.00	$471,957.65	$3,919.63	0.8%

EXHIBIT HS-8

Traffic Signal & Street Lighting

WINTER

	BILL IMPACTS CURRENT RATES					
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
			$0.04760	$0.031532	$0.00682	
Xsm	169		$8.04	$5.33	$1.15	$14.52
Small	1,180		$56.17	$37.21	$8.05	$101.43
Medium	4,370		$208.01	$137.79	$29.80	$375.60
Large	7,560		$359.86	$238.38	$51.56	$649.80
XLg	9,300		$442.68	$293.25	$63.43	$799.36
AnnAvg	2,484		$118.25	$78.33	$16.94	$213.52
TSSLAvg	2,687		$127.89	$84.72	$18.32	$230.93

	BILL IMPACTS PROPOSED RATES							
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill		
			$0.05400	$0.032537	$0.00000			
							$ Change	% Change
Xsm	169		$9.13	$5.50	$0.00	$14.63	$0.11	0.8%
Small	1,180		$63.72	$38.39	$0.00	$102.11	$0.68	0.7%
Medium	4,370		$235.98	$142.19	$0.00	$378.17	$2.57	0.7%
Large	7,560		$408.24	$245.98	$0.00	$654.22	$4.42	0.7%
XLg	9,300		$502.20	$302.59	$0.00	$804.79	$5.43	0.7%
AnnAvg	2,484		$134.14	$80.83	$0.00	$214.97	$1.45	0.7%
TSSLAvg	2,687		$145.08	$87.42	$0.00	$232.50	$1.57	0.7%

EXHIBIT HS-8

Traffic Signal & Street Lighting

Summer

	BILL IMPACTS CURRENT RATES					
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
			$0.04760	$0.035111	$0.00682	
Xsm	170		$8.09	$5.97	$1.16	$15.22
Small	1,020		$48.55	$35.81	$6.96	$91.32
Medium	3,599		$171.31	$126.36	$24.55	$322.22
Large	6,200		$295.12	$217.69	$42.28	$555.09
XLg	7,500		$357.00	$263.33	$51.15	$671.48
AnnAvg	2,484		$118.25	$87.22	$16.94	$222.41
TSSLAvg	2,204		$104.93	$77.40	$15.03	$197.36

	BILL IMPACTS PROPOSED RATES							
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill		
			$0.05400	$0.035868	$0.00000			
							$ Change	% Change
Xsm	170		$9.18	$6.10	$0.00	$15.28	$0.06	0.4%
Small	1,020		$55.08	$36.59	$0.00	$91.67	$0.35	0.4%
Medium	3,599		$194.35	$129.09	$0.00	$323.44	$1.22	0.4%
Large	6,200		$334.80	$222.38	$0.00	$557.18	$2.09	0.4%
XLg	7,500		$405.00	$269.01	$0.00	$674.01	$2.53	0.4%
AnnAvg	2,484		$134.14	$89.10	$0.00	$223.24	$0.83	0.4%
TSSLAvg	2,204		$119.04	$79.07	$0.00	$198.11	$0.75	0.4%

EXHIBIT HS-8

Area Lighting

	BILL IMPACTS CURRENT RATES				
	kWh	Delivery	Base Fuel	PPFAC	Net Bill
				$0.00682	
Xsm	93	$8.19	$0.85	$0.63	$9.67
Small	124	$23.72	$0.94	$0.85	$25.51
Medium	215	$23.72	$1.34	$1.47	$26.53
Large	720	$12.29	$3.36	$4.91	$20.56
XLg	1,339	$18.70	$5.38	$9.13	$33.21
Pole	0	$2.86	$0.00	$0.00	$2.86
ALAvg	316	$8.19	$1.34	$2.15	$11.68

	BILL IMPACTS PROPOSED RATES						
	kWh	Delivery	Base Fuel	PPFAC	Net Bill		
				$0.00000			
						$ Change	% Change
Xsm	93	$9.97	$0.86	$0.00	$10.83	$1.16	12.0%
Small	124	$28.87	$0.96	$0.00	$29.83	$4.32	16.9%
Medium	215	$28.87	$1.36	$0.00	$30.23	$3.70	13.9%
Large	720	$14.96	$3.42	$0.00	$18.38	-$2.18	-10.6%
XLg	1,339	$22.76	$5.47	$0.00	$28.23	-$4.98	-15.0%
Pole	0	$3.48	$0.00	$0.00	$3.48	$0.62	21.7%
ALAvg	316	$9.97	$1.36	$0.00	$11.33	-$0.35	-3.0%

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239

DIRECT TESTIMONY

IN SUPPORT OF

SETTLEMENT AGREEMENT

ELIJAH O. ABINAH

ASSISTANT DIRECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 26, 2016

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EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NOS. E-01933A-15-0239 AND E-01933A-15-0322

Mr. Abinah's testimony supports the adoption of the Settlement Agreement ("Agreement") as proposed by the Signatories in this case. This testimony describes the settlement process as open, candid, transparent and inclusive of all Signatories to this case. Mr. Abinah explains why Staff believes this Agreement is in the public interest.

Mr. Abinah's testimony recommends that the Commission adopt the Agreement as proposed.

I. – INTRODUCTION

Q. Please state your name and business address.

A. My name is Elijah O. Abinah. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("Commission" or "ACC") as Assistant Director of the Utilities Division ("Staff").

Q. How long have you been employed with the Utilities Division?

A. I have been employed with the Utilities Division since January 2003.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in Accounting from the University of Central Oklahoma in Edmond, Oklahoma. I also received a Master of Management degree from Southern Nazarene University in Bethany, Oklahoma. Prior to my employment with the ACC, I was employed by the Oklahoma Corporation Commission for approximately eight and a half years in various capacities in the Telecommunications Division.

Q. What are your current responsibilities?

A. As an Assistant Director, I review submissions that are filed with the Commission and make policy recommendations to the Director regarding those filings.

Q. Have you previously submitted testimony before the Commission?

A. Yes.

Q. What is the subject matter of your testimony?

A. The purpose of my testimony is to support the Settlement Agreement ("Agreement"). I will also provide testimony which addresses the settlement process, public interest benefits and general policy considerations.

Q. Does this Agreement settle the case in its entirety?

A. No, the Agreement proposes a settlement regarding Tucson Electric Power Company's ("TEP" or "Company") revenue requirement.

Q. Did you participate in the negotiations that led to the execution of the Agreement?

A. Yes, I did.

Q. How is your testimony being presented?

A. My testimony is organized into five sections. Section I is this introduction, Section II provides a discussion of the settlement process, Section III discusses the various parts of the Agreement, Section IV discusses the reasons why the Agreement is in the public interest and Section V discusses policy considerations.

II – SETTLEMENT PROCESS

Q. Mr. Abinah, please discuss the settlement process.

A. The settlement process was open, transparent and inclusive. All parties received notice of the settlement meeting and were accorded an opportunity to raise, discuss, and propose resolution to any issue that they desired.

Q. Did all parties participate in the settlement process?

A. No, although all parties certainly were given the opportunity to participate, since the Agreement only addresses TEP's revenue requirement, only those parties that had issues regarding revenue requirement or otherwise wanted to participate, actually participated in the settlement process.

Q. Who participated in the meeting?

A. The following parties were participants in some or all of the meeting: TEP, the Residential Utility Consumer Office ("RUCO"), the Arizona Investment Council ("AIC"), the Southwest Energy Efficiency Project ("SWEEP"), Arizona Public Service Company ("APS"), the Department of Defense on behalf of Federal Executive Agencies ("DoD"), Kroger Co. ("Kroger"), Freeport Minerals Corporation ("Freeport Minerals"), Arizonans for Electric Choice and Competition ("AECC"), IBEW Local 1116 ("IBEW"), the Sierra Club ("Sierra"), Western Resource Advocates ("WRA"), Wal-Mart Stores, Inc. and Sam's West, Inc., SOLON Corporation, Vote Solar, Energy Freedom Coalition of America, Noble America Energy Solutions, LLC, Pima County and Staff.

Q. Was there an opportunity for all issues related to the revenue requirement to be discussed and considered?

A. Yes, each party had the opportunity to raise and have its issues considered.

Q. Were the Signatories able to resolve all issues related to the revenue requirement?

A. Yes, although there were issues that were eventually excluded from the Agreement and will be litigated, all of the Signatories were able to resolve and reach agreement on all issues related to the revenue requirement to their satisfaction.

Q. How would you describe the negotiations?

A. I believe that all participants advocated and represented their interests well. I would characterize the discussions as candid but professional. While acknowledging that not all participants executed the Agreement, I must re-emphasize that all participants had the opportunity to be heard and to have their issues fairly considered.

Q. Would you describe the process as requiring give and take?

A. Yes, I would. As a result of the varied interests represented in the settlement process, a willingness to compromise was necessary. As evidenced in the Agreement, the Signatories compromised on what could be described as vastly different litigation positions.

Q. Because of such compromising, do you believe the public interest was compromised?

A. No. As I will discuss later in this testimony, I believe the compromises made by the Signatories further the public interest.

Q. What is the revenue increase and cost of equity requested by the Company?

A. TEP requested a net increase in base rates of $109.5 million, which included a requested cost of equity of 10.35 percent.

Q. What is the revenue increase and cost of equity that was recommended by Staff?

A. Staff recommended a net increase in base rates of $49.9 million, and a 9.35 percent cost of equity.

Q. What is the revenue increase and cost of equity recommended by the Agreement?

A. The Signatories recommend a non-fuel base rate increase of approximately $81.5 million, which includes a 9.75 percent cost of equity.

III – AGREEMENT

Q. Mr. Abinah, please describe Part II of the Agreement?

A. Part II describes the recommended rate increase agreed to by the Signatories. In its application, TEP requested a non-fuel base rate increase of $109.5 million; however, the Signatories agreed to an increase of approximately $81.5 million, which is $28 million less than the Company requested. In addition, the Signatories agreed to and recommended an average base fuel rate be set to $0.0325559 to recover $289,147,243 in base fuel revenues. TEP's total revenue requirement shall be $1,003,170,143. The Company's jurisdictional fair value rate base ("FVRB") used to establish rates is $2,843,985,854, representing an average of the original cost rate base ("OCRB") of $2,045,203,460 and the replacement cost new less depreciation rate base ("RCND")of $3,633,027,972.

Q. What are the other provisions of Section II?

A. Section II also addresses the treatment of TEP's proposed purchase of Unit 1 of the Springerville Generating Station ("SGS Unit 1). TEP had originally proposed to recover this amount through its Purchased Power and Fuel Adjustment Clause ("PPFAC"). The recovery of this amount through non-fuel rates represents a revenue neutral change to the agreed upon revenue requirement. Of the recommended non-fuel revenues, $15,243,913 is contingent upon TEP purchasing a 50.5 percent share of SGS Unit 1. This portion of the rate increase will not be effective until after the purchase has been completed and a final Order has been issued.

Q. Please explain Section III of the Agreement.

A. A capital structure comprised of 49.97 percent long-term debt and 50.03 percent common equity is proposed. In addition, the Signatories recommended a return on common equity of 9.75 percent and an embedded cost of long-term debt of 4.32 percent, resulting in a weighted

average cost of capital of 7.04 percent. Also, the Signatories proposed a fair value rate of return of 5.34 percent which includes a rate of return on the fair value increment of rate base of 1.00 percent.

Q. Please describe Section IV.

A. Section IV describes the depreciation and amortization rates. The rates proposed by TEP would be adopted except: (i) the rates for San Juan Generating Station shall be adjusted to reflect a depreciable life of TEP's total investment, including the Balanced Draft project, at San Juan Unit 1 of six (6) remaining years; (ii) $90 million of excess distribution reserves will be transferred to San Juan Unit 1 and (iii) a reduction to depreciation rates on TEP's distribution plant to offset the increase in depreciation expense for San Juan Unit 1. TEP will file, with its testimony in support of the Agreement, schedules setting forth the applicable depreciation and amortization rates, including those for San Juan Unit 1.

Q. As compared to Staff's original position to support a net increase in base rates of $49.9 million, what are the major specific items Staff conceded in the Agreement in agreeing to an $81.5 million increase?

A. Of the major items Staff conceded were the inclusion of post-test year plant that was verified in-service one year after the test year. In Staff's direct testimony, Staff limited the inclusion of post-test year plant to 6 months. Staff determined that one year was a reasonable compromise.

Additionally, Staff, in an effort to compromise, agreed to a return on common equity of 9.75 percent. Staff's position on return on equity in direct testimony was 9.5 percent. The Company, in its rebuttal testimony, reduced its return on equity request from 10.35 percent to

10.00 percent. In TEP's last rate case, the Commission granted TEP a 10 percent return on equity. Staff conclude that 9.75 percent was a reasonable compromise.

Q. Please describe Section V.

A. Section V sets forth additional conditions relating to SGS Unit 1. TEP has agreed to not request rate base treatment of the purchase price paid for the 50.5 percent share of SGS Unit 1 until its next general rate case. The leasehold improvements associated with the 50.5 percent share of SGS 1 shall be updated in the OCRB at the Net Book Value as of December 31, 2016.

Q. Please describe Section VI.

A. In an effort to address issues raised by some of the Signatories, the Company agrees to the following:

- TEP will write down the Net Book Value of its headquarters building by $5 million, resulting in a $5 million reduction to the total Company OCRB within 30 days of the issuance of a final order in this proceeding. In return, the Signatories agree that they will not seek alternative rate treatment or additional write-downs of the headquarters building in further rate proceedings.
- Post-test year plant, in the amount of $49.6 million and post-test year renewable generation plant of $4.8 million, that is verified and in-service as of June 30, 2016, shall be included in the Company's OCRB.
- Because this is a partial settlement, certain issues, such as class cost of service allocations, rate design, the Buy Through and the Lost Fixed Cost Recovery mechanism and net metering remained unresolved and will be litigated. The

Signatories will present their respective positions in Surrebuttal testimony and at the hearing scheduled in this matter.

IV – PUBLIC INTEREST

Q. Mr. Abinah, is the Agreement in the public interest?

A. Yes, in Staff's opinion, the Agreement is fair, balanced, and in the public interest.

Q. Would you summarize the reasons that led Staff to conclude that the Agreement is fair, balanced, and in the public interest?

A. This Agreement results in a settlement that addresses TEP's demonstrated needs; promotes the convenience, comfort and safety, and the preservation of health, of the employees and patrons of TEP; resolves revenue requirement issues arising from this Docket; and avoids additional litigation expense and delay relating to the revenue requirement.

Q. Please discuss how the Agreement is fair to the utility.

A. The revenue recommended will provide TEP with adequate funds to provide reliable and safe service, while at the same time ensuring the financial health of the Company.

Q. Mr. Abinah, what was Staff's goal when it agreed to be a Signatory to the Agreement?

A. The primary goal of Staff in this matter, as in all rate proceedings before the Commission, is to protect the public interest by recommending rates that are just, fair and reasonable for both the ratepayers and the Company. Staff believes it has accomplished this by reviewing the facts presented and making the appropriate recommendations to the Commission for its consideration, which will balance the interests of the Company and the ratepayers, by promoting the Commission's desire to ensure that the Company has the tools and financial

health to provide safe, adequate and reliable service, while complying with Commission requirements at just and reasonable rates.

V – POLICY CONSIDERATIONS

Q. What were the major policy considerations the Signatories had to deal with in this Docket?

A. TEP has proposed changes in net metering as well as mandatory three-part rates for new distributed generation ("DG") customers. These issues were also proposed by TEP's affiliate, UNS Electric, Inc. ("UNSE"). The Commission recently issued Decision No. 75697 ("Decision") that approved an application for a rate increase for UNSE. The Commission's Decision ordered that the UNSE rate case be kept open for consideration of several issues in a "Phase 2" proceeding that will commence following the issuance of a final Order in the Commission's Investigation of Value and Cost of Distributed Generation, Docket No. E-00000J-14-0023 ("Value of DG Docket"). Those issues that remain for Phase 2 of UNSE, include, but are not limited to, net metering. Because of the similarity in issues, the Company filed a motion to modify the scope of the hearing in this docket, consistent with the Commission's decision in UNSE. Staff supported the motion. On August 22, 2016, a procedural order was issued which granted the Company's motion.

Q. Is there anything else you would like to add regarding the Agreement?

A. I would like to reiterate that the settlement discussions were transparent, candid, professional and open to all parties in this docket. All Signatories were allowed to openly express their views and opinions on all issues. I believe the Settlement Agreement is in the public interest.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-01933A-15-0322

DIRECT

TESTIMONY

OF

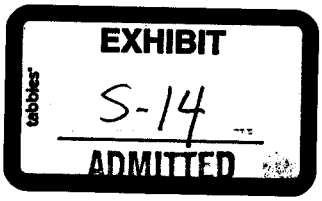
CANDREA ALLEN

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 3, 2016



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EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-15-0322

My testimony addresses Tucson Electric Power Company's proposed changes to its Rules and Regulations.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Candrea Allen. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff") as a Public Utilities Analyst. I provide recommendations on various utility applications to the Commission. I have been employed by the Commission since 2006.

Q. As part of your responsibilities were you assigned to review matters contained in this Docket?

A. Yes.

Q. What is the scope of your testimony in this case?

A. My testimony will be limited to Staff's positions and recommendations relating to Tucson Electric Power Company ("TEP" or "Company") proposed changes to its Rules and Regulations.

DIRECT TESTIMONY

Q. Will you be addressing all of the changes TEP has proposed in this rate case?

A. No. Many of TEP's proposed changes are non-substantive and merely clarifications to the current Rules and Regulations. Staff supports these proposed changes.

I will only be addressing what Staff believes to be the substantive changes proposed by TEP included in the Direct Testimony of Craig Jones and Denise Smith. Staff's recommendations are discussed below, by section of the Rules and Regulations.

Section 3 – Establishment of Service

Q. What changes are being proposed to Section 3 of TEP's Rules and Regulations?

A. TEP is proposing to delete language regarding customer deposits from Section 3.B.1.a which currently reads:

> The Applicant has had service of a comparable nature with the Company within the past two (2) years and was not delinquent in payment *more than* twice during the last twelve (12) consecutive months of service or was not disconnected for nonpayment. [Emphasis added.]

TEP is proposing to remove the words ***more than*** from the sentence.

Q. Does Staff agree with TEP's proposed revision?

A. No. The current language in Subsection 3.B.1.a. of TEP's Rules and Regulations is the precise language from Arizona Administrative Code ("A.A.C.") R14-2-203.B.1.a. Staff believes that removing the words ***more than*** from TEP's current language would be inconsistent with A.A.C. R14-2-203.B.1.a. Therefore, Staff does not recommend approval of TEP's proposed revision to Section 3.

Section 4 – Minimum Customer Information Requirements

Q. What changes are being made to Section 4 of TEP's Rules and Regulations?

A. TEP is proposing to add language that would allow the Company to charge its customers when a customer requests consumption history and/or interval data history. The proposed

Consumption History Request and Interval History Request charge is also reflected in TEP's Statement of Charges at $65.00 per hour of customer support.

Q. What are Staff's recommendations regarding the proposed changes to Section 4?

A. The Direct Testimony of Craig Jones indicates that the proposed charge only applies should a customer request this information more than once in a 12-month period. Staff believes, that for clarification, the proposed language should specify that for a customer requesting consumption history, the charge would apply only when the request is made more than once in a 12-month period. For a customer requesting interval history the charge would be for each request made. Staff recommends inserting the following sentence to Section 4.A.6.:

> This charge will apply for each interval history request made or when Customers request their consumption history more than once in a 12-month period.

Staff notes that this language is the same language that UNS Electric, Inc. included in its Rules and Regulations (Docket No. E-04204A-15-0142). Staff believes this language adds clarity to this section. The Statement of Charges should also reflect Staff's recommendation, as a footnote.

In addition, Staff notes that the Direct Testimony of Staff Consultant Howard Solganick will be addressing the proposed consumption history/interval data history charge as part of Statement of Charges in rate design testimony scheduled to be filed on June 24, 2016. Any recommendations included in the testimony of Mr. Solganick regarding the proposed consumption history/interval data history charge that may impact the language included in the Rules and Regulations should also be incorporated.

Section 10-Meter Reading

Q. What changes are being made to Section 10 of TEP's Rules and Regulations?

A. TEP is proposing to add Automated Meter Opt-Out language that would allow customers to request meters that do not transmit data wirelessly. TEP would charge a Special Meter Reading Fee and Automated Meter Opt-Out Set-Up Fee for those customers as specified in its Statement of Charges.

Q. What are Staff's recommendations regarding the proposed changes to Section 10?

A. For those customers who choose to not have an automated meter installed or wish to replace an automated meter with a non-transmitting meter, the Special Meter Reading Fee (which would apply to customer self-reads) would be a monthly recurring charge of $26.00. Therefore, Staff recommends that TEP clarify that customers will only be subject to the Special Meter Reading Fee on a monthly basis should they request to replace an automated meter with a non-transmitting meter or continue the use of a non-transmitting meter.

Staff also recommends that TEP clarify that the proposed Automated Meter Opt-Out Set-Up Fee of $187.00 will only apply to those customers who request the removal of an automated meter. If a customer currently has a non-transmitting meter, the customer would not be subject to the proposed Automated Meter Opt-Out Set-Up Fee. Staff recommends the following be added to Section 10.H.:

> For Customers who choose to not have an automated meter installed or wish to replace an automated meter with a non-transmitting meter, the Special Meter Reading Fee set forth in Fee No. 3 in the TEP Statement of Charges will be a monthly recurring charge. The Automated Meter Opt-Out Set-Up Fee set forth as Fee No. 8 in the TEP Statement of Charges will only apply to those Customers who request the removal of an automated meter.

Staff notes that this language is similar to the UNS Electric, Inc. language included in its Rules and Regulations (Docket No. E-04204A-15-0142). Staff believes this language adds clarity to this section. The Statement of Charges should also reflect Staff's recommendation, as a footnote.

Staff notes that the Direct Testimony of Staff Consultant Howard Solganick will be addressing the amount of the proposed Special Meter Reading Fee and Automated Meter Opt-Out Set-Up Fee as part of Statement of Charges in rate design testimony scheduled to be filed on June 24, 2016. Any recommendations included in the upcoming testimony of Mr. Solganick regarding the proposed Special Meter Reading Fee and Automated Meter Opt-Out Set-Up Fee that may impact the language included in the Rules and Regulations should also be incorporated.

Section 11-Billing and Collection

Q. What changes are being made to Section 11 of TEP's Rules and Regulations?

A. TEP is proposing the following changes to Section 11 that Staff believes need to be clarified.

1) TEP is proposing to modify Subsection 11.I.6. Staff does not oppose the proposed change. However, Staff recommends that TEP add "listed in the Statement of Charges" to the end of the sentence to read:

> A deferred payment agreement does not relieve the unpaid balance from being assessed a monthly late charge, in accordance with the current late payment fee percentage rate listed in the Statement of Charges as Fee No. 15.

Staff notes that the language in this Subsection is similar to the UNS Electric, Inc. language included in its Rules and Regulations (Docket No. E-04204A-15-0142). Staff believes this language adds clarity to this section.

2) TEP is proposing to modify Subsection 11.L.2 by replacing the word "incurred" to "assessed". Staff does not oppose the proposed change. However, for clarification purposes, Staff recommends that TEP add "by the Company or its Agent" to the end of the sentence to read:

> If a collection agency referral is warranted for collection of unpaid final bills, Customer will be responsible for associated collection agency fees assessed by the Company or its Agent.

Staff notes that the language in this Subsection is the same as the language that UNS Electric, Inc. included in its Rules and Regulations (Docket No. E-04204A-15-0142). Staff believes this language adds clarity to this section.

Section 12-Termination of Service

Q. What changes are being made to Section 12 of the Rules and Regulations?

A. In the direct testimony of Denise Smith, TEP proposes to add Subsection 12.H which reads:

> In the event a Customer provides the Company with documentation certifying that the Customer depends on electricity to power a life-sustaining medical device or if a Customer's medical condition warrants continuous electrical service and the Customer accumulates debt equivalent to a three (3) month bill, in lieu of disconnection of service, the Company may limit the amount of current flowing into the premises to operate medical devices and basic appliances, such as refrigeration, water supply, lighting and small motors in the heating system.

However, in response to Staff's data request, TEP has indicated that it intends to withdraw Subsection 12.H in the Company's rebuttal testimony to be filed July 25, 2016. Staff notes that in the UNSE rate case, UNSE also chose to ultimately withdraw this language from its Rules and Regulations. Staff would have no objection to the withdrawal of this proposed language from TEP's Rules and Regulations.

SUMMARY OF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff makes the following recommendations:

- TEP revise the language in Subsection 4.A.6. to clarify that the consumption history/interval data history charge only applies if a customer requests the information more than once in a 12-month period. The Statement of Charges should also reflect Staff's recommendation.

- TEP revise the proposed language in Subsection 10.H to: a) specify that customers will be subject to the Special Meter Reading Fee on a monthly basis when they request to continue to use a non-transmitting meter or replace an automated meter with a non-transmitting meter; and b) clarify that the Automated Meter Opt-Out Set-Up Fee will only apply to those customers who currently have an automated meter but request that the automated meter be removed and replaced by a non-transmitting meter. Customers who currently have a non-transmitting meter would not be subject to the proposed Automated Meter Opt-Out Set-Up Fee. The Statement of Charges should also reflect Staff's recommendations.

- TEP add "listed in the Statement of Charges as Fee No. 15." to the end of Subsection 11.I.6.

- TEP add "by the Company or its Agent." to the end of Subsection 11.L.2

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239

SURREBUTTAL

TESTIMONY

OF

CANDREA ALLEN

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 26, 2016

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TUCSON ELECTRIC POWER COMPANY
DOCKET NOS. E-01933A-15-0239 AND E-01933A-15-0322

My surrebuttal testimony addresses the rebuttal testimony of Tucson Electric Power Company's witness Denise Smith regarding the Company's proposed changes to its Rules and Regulations.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Candrea Allen. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff") as a Public Utilities Analyst.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony regarding the proposed changes to Tucson Electric Power Company's ("TEP" or "Company") Rules and Regulations.

Q. What is the scope of your surrebuttal testimony in this case?

A. My surrebuttal testimony addresses the rebuttal testimony of TEP witness Denise Smith regarding the Company's Rules and Regulations.

SURREBUTTAL TESTIMONY

Section 11 – Billing and Collection

Q. What change is TEP proposing to Section 11 – Billing and Collection of its Rules and Regulations?

A. TEP is proposing to revise the language added as Subsection 11.F.3.e. This item was not addressed in Staff's direct testimony because Staff did not feel that the proposed language was substantive and had no concerns with its inclusion in TEP's Rules and Regulations.

Q. What does the current language in Subsection 11.F.3.e currently read?

A. Currently, the proposed language added as Subsection 11.F.3.e. reads:

> When a Customer signs up for services in error at the wrong premise.

Q. What is the revised language TEP is proposing?

A. In the rebuttal testimony of TEP witness Denise Smith, she indicates that TEP is revising proposed language added submitted as Subsection 11.F.3.e to read:

> When a Customer signs up for service in error at the wrong premises or requests disconnection in error at the wrong premises, corrected charges for under billings shall go back to the date of the error.

Q. Does Staff agree with TEP's revised proposed language to Subsection 11.F.3.e.?

A. Yes. Staff agrees with the inclusion of the additional language. However, Staff recommends modifications to the proposed language.

Q. What is Staff's recommendation regarding TEP's proposed revision to Subsection 11.F.3.e.?

A. Staff recommends that additional language be added to include instances of over-billing under the circumstances described. Therefore, Staff recommends the following language:

> When a Customer signs up for service in error at the wrong premises or requests disconnection in error at the wrong premises, corrected charges for under-billings ***and/or credits for over-billings*** shall go back to the date of the error. **[Emphasis added]**

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-01933A-15-0322

DIRECT RATE DESIGN

TESTIMONY

OF

MATT CONNOLLY

EXECUTIVE CONSULTANT II

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 24, 2016

EXHIBIT
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ADMITTED

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EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NOS. E-01933A-15-0322 AND E-01933A-15-0239

Staff's testimony contains analysis and recommendations regarding Tucson Electric Power Company's ("TEP") request for the implementation of an optional Prepay Metering Program and its request for the elimination of certain compliance requirements.

Regarding TEP's proposed Prepay Metering Program, the Arizona Corporation Commission Utilities Division ("Staff") recommends the following:

- The Program be approved as a Pilot Program for at least twenty-four months.
- The Program exclude customers relying on an electrical device for medical survival.
- The Program not be included in TEP's Energy Efficiency portfolio.
- TEP receive a waiver from providing a written disconnect notice as required under the Arizona Administrative Code ("A.A.C.") § R14-2-211(D) for the purposes of this Program.
- TEP Lifeline customers be allowed to participate in the Program.
- TEP modify its Prepay Service Agreement in accordance with Staff's recommendations and file it with Staff for analysis, review and approval prior to the implementation of the Program.
- The rates and charges may need to be revised, pending Staff review.

Regarding TEP's request to be relieved of certain compliance requirements, Staff recommends the following:

- The following Retail Electric Competition Rules be suspended until further order of the Commission:
  - Systems Benefit Charge Filing (R14-2-1608 (A))
  - Annual Electric Competition Filing (R14-2-1613 (A) and (B))
  - Annual Consumer Information Label (R14-2-1617 (A), (C), (D) and (G))
  - Annual Disclosure Report (R14-2-1617 (G) and (E))

- TEP continue to file an Annual Update to its Electric Load Curtailment Plan as required by Decision No. 66034.

- TEP be relieved of the requirement that it file a report every (5) five years listing potential improvements to Springerville Units 1 and 2 that reduce emissions and costs associated with the improvements as ordered by Decision No. 65347, dated November 1, 2002.

- TEP be relieved of the requirement that it file an Annual Cost Containment Report required initially by Decision No. 59594.
- TEP continue to file an Annual Estimated First or Final Bill Report as required by Decision No. 64180.

- TEP be relieved of the requirement that it file a Full Decoupling Report in connection with its Lost Fixed Cost Recovery ("LFCR") annual adjustment as required by Decision No. 73912.

- TEP be relieved of the requirement that it file an Annual Letter of TEP's Code of Conduct as required by Decision No. 62767.

- TEP be relieved of the requirement that it file an Annual Summer Preparedness Report for the Cyprus Sierrita substation Certificate of Environmental Compatibility ("CEC") as required by Decision No. 69680.

- TEP be relieved of the requirement that it file an Annual Sign Replacement Report for the Cyprus Sierrita substation CEC as required by Decision No. 69680.

- UNS Electric continue to file an Annual Self-Certification Letter identifying progress made with the conditions set out in the CEC for the Vail substation to the Valencia substation as required by Decision No. 71282.

- TEP be relieved of the requirement that it file an Annual Self-Certification Letter identifying which conditions have been met in the CEC authorizing construction of a double circuit, 345 kV transmission line running from TEP's South 345 kV Substation to a proposed TEP Gateway Substation in Nogales, Arizona in Santa Cruz County with a 115 kV interconnection to the 115 kV Valencia Substation and 345 kV line to the international border as required by Decision No. 64536.

- TEP be relieved of the requirement to develop a data base of existing renewable energy resources within its service area within six months from the effective date (June 1, 1994) of Decision No. 58643, revise it annually and submit to Staff each year as part of the historical data filings required under Integrated Resource Planning rules (R14-2-703 (A) and (B)).

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Matt Connolly. I am an Executive Consultant II employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as an Executive Consultant II.

A. I provide information, analysis and support to Staff on utility-related filings, applications and a variety of other utility-related matters.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Arts Degree in History from Westminster College in Fulton, Missouri.

Since joining the Commission in June of 2014, I have participated in numerous cases and regulatory proceedings involving electric, gas, water, and telecommunication utilities. I have testified on matters involving telecommunications applications for Certificates of Convenience and Necessity and a Rulemaking. Additionally, I have attended utility-related seminars sponsored by the National Association of Regulatory Utility Commissioners ("NARUC") and the National Regulatory Research Institute ("NRRI") on a variety of utility regulation matters.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. E-01933A-15-0322?

A. Yes.

Q. What is the scope of your testimony in this case?

A. I am presenting Staff's analysis and recommendations in response to Tucson Electric Power Company's ("TEP") request for the implementation of an optional Prepay Metering Program ("Program"). I am also presenting Staff's analysis and recommendations in response to TEP's request to be relieved of a number of compliance items.

THE COMPANY REQUESTED PREPAY PROGRAM

Q. Please describe TEP's proposed Prepay Program.

A. TEP is proposing to offer an optional Prepay Metering Program as a permanent service offering for customers who want to pay in advance for their electrical service. As described in the filed testimony of TEP's witness, Ms. Denise Smith, the TEP Program will be available to all residential customers as a stand-alone tariff except for those who are dependent upon electrical devices for health-related reasons. It proposes to offer the benefits of waivers of a service security deposit and reconnection/disconnection field service charges; no late payment fees for non-payment; access to daily energy use information in order to understand and control energy usage; TEP-provided energy efficiency tips and educational materials, and access to customizable low balance alerts to aid in the assistance of energy use management and payment scheduling.

TEP states in the testimony of Mr. Craig Jones, the Prepay rate is a blended per kWh rate that is based on the weighted average of the two energy rate tiers for the Residential Electric Service Tariff (R-01). The first rate of $0.064000 will be assessed for the first twenty (20) kWh per day both in summer and winter and a second rate of $0.079000 will be applied to kWh over 20.[1] The Program will also have a $20 monthly basic service charge plus a $2 fee to

[1] In response to Staff DRs STF 17.30 and 17.31, TEP explains that the second Prepay tier was created as residential customers who use over 600 kWh per month on the Program would have a lower monthly bill if just a single Prepay tier were in place. The TEP Residential R-01 tariff indicates an energy rate of $0.079100 for over 500 kWhs per month.

cover the cost of the new cellular system required by the meter to facilitate on demand disconnection and reconnection, a $1 fee for the partial recovery of the cost of the required customer premise meter and a $2 fee for the cost of upgrading the data management system and billing interface required to provide the Prepay service. A total charge of $25.00 divided by a thirty day period results in an approximate per day service charge of $0.84. According to the proposed Prepay Service Agreement and in response to Staff DR STF 17.53, a customer will be required to pay at least $20.00 to establish a Program balance.

In addition, TEP proposes to adopt the following customer protections: TEP will provide all Program customers a Prepay Service Agreement and Welcome Packet that includes information about energy efficiency opportunities; will not enroll any customer who has not acknowledged they have read the Prepay Service Agreement[2]; will not enroll in Prepay any customers who have significant medical issues or require the assistance of electrically powered medical devices; will deliver low balance/disconnect alerts via phone, text or email; will only disconnect a customer after a four (4) hour grace period following a disconnect alert[3]; will not disconnect a customer during an extreme weather event or during non-business hours[4]; and will document disconnections and provide documentation of disconnection history to limited-income customers to support bill assistance applications.

TEP will also include in the Program a 75/25 payment option which will enable a Prepay customer the opportunity to pay off an outstanding balance. For customers who select this option, 75 percent of their payment will be applied to their prepaid energy balance and 25

[2] In response to Staff DR STF 17.21, TEP indicated that acknowledgement will occur consistent with the selected enrollment channel. Customers enrolling via the web-based access will be prompted to select and click an acknowledgment prompt after being presented with an electronic copy of the terms and conditions. Customers enrolling over the telephone will be read an abridged version of the terms and conditions and asked for a verbal acknowledgement which will be documented by the customer service representative. In all cases a customer will receive a mailed copy delivered to their service address.

[3] In response to Staff DR STF 17.52, TEP indicates the Company is in the bid process for a payment solutions vendor and anticipates most payment options to be posted within 30 minutes of receipt.

[4] In response to Staff DR STF 17.24, TEP defines an extreme weather event as a day when the high temperature is expected to hit 110 degrees or, in cold climates, not to exceed 32 degrees.

percent will be applied to the reduction of the outstanding balance. For example, as described in the response to Data Request ("DR") STF 17.18, a customer who has an average $2.50 daily energy use will be required to pay an additional $0.83 daily which would be applied toward the outstanding balance. Any customer who has an outstanding balance and who wishes to select the Program will either have to enroll in this option or pay off their outstanding balance in full before they can be admitted to the Program.

As described in response to Staff DR STF 17.34, in order for a customer to participate in the Program, TEP must install a special meter with 2-way communication capability that includes the ability for remote disconnect and reconnect.[5] TEP also plans to enhance and upgrade the interface between its Meter Data Management ("MDM") hub and its Customer Care and Billing ("CC&B") system in order to provide customers with daily energy usage and account balance data. In response to DR STF 17.19, TEP stated that several of the upgrades required for the MDM system are slated for completion in late first quarter of 2017. Customizations of the CC&B system unique to the Program will only take place upon Commission approval of the Program which will take approximately twelve (12) months to complete. TEP also plans to introduce a new mobile application to allow customers to manage payments, receive outage notifications and view past and present usage. However, as described in the response to Staff DR STF 17.20, a customer without a smartphone will, in the alternative, be able to make prepayments and access information via TEP's online account manager or via telephonic Interactive Voice Response ("IVR") or at a participating retail location (the latter subject to a transaction fee).

[5] In response to Staff DR STF 17.33, if the customer resides in a single unit of a multi-unit dwelling serviced by a single meter, the customer would not be eligible for the Program.

Q. TEP is proposing to offer its Program as a permanent service offering. Does Staff agree with this decision?

A. No. Staff believes the Program should be offered as a Pilot. TEP is proposing a third-party evaluation of the Program not less than 24 months after (i) the launch of customer enrollment, and (ii) two successive "high bill" seasons. In response to Staff DR STF 17.26, TEP will use the following criteria to judge the success of the Program when filtered for the impacts of disconnection and participation in other Energy Efficiency ("EE") programs: does the program result in a customer reduction of energy consumption; are participating customers satisfied with their experience and whether customers report a feeling of empowerment and in control of their energy usage and spending when assessed against other customers not in the Program. While Staff has no issues with the proposed criteria, Staff is of the opinion that measurement using these criteria would be better served to discover the value and interest in the program before it becomes permanent. Additionally, in response to Staff DR STF 17.37, TEP is projecting up to 20 percent of its customers may elect to participate in the Program and is a "popular option for many customers with satisfaction typically very high." However, as TEP admits it is relying on the experience of other utilities, introducing its own Program as a pilot will provide the opportunity to validate these assumptions. Finally, while the rates and charges for this Program are based on calculations derived from the TEP Residential R-01 offering, they are not derived from the actual experience for a TEP Prepay program. Twenty-four months of Pilot time will serve to help ground rates and charges in reality and, as this is not an option TEP is considering now with the Program, perhaps help TEP to broaden the availability of the Program to such other options as Time of Use customers.

Q. Does Staff believe it is appropriate to exclude customers from the Program who are dependent upon electrical devices for health-related reasons?

A. Yes. TEP stated in its response to DR STF 17.16 that it lacks the medical expertise to evaluate on a case-by-case basis the appropriateness of the Program for customers in this situation. Staff believes a customer relying on an electrical device for medical survival should not be subject to possible disconnect due to a zero bank balance.

Q. TEP has indicated it will be including the Program as part of its portfolio of EE programs to encourage customer energy conservation and count the Program towards meeting the EE Standard. Does Staff believe such inclusion is appropriate?

A. No. In response to Staff Data Request STF 17.145, TEP states that prepay programs in other jurisdictions have demonstrated reduction in energy consumption by participants such as Salt River Project's M-Power program which recorded a 12 percent effect and Arizona Public Service's prepay pilot program which saw a 7.16 percent energy savings. Staff is not convinced any program that is designed to cut off power due to the customer's inability to pay is in accordance with the Arizona Administrative Code ("A.A.C.") § R14-2-2401(17) definition of EE which means "the production or delivery of an equivalent level and quality of end-use electric service using less energy, or the conservation of energy by end-use customers." While TEP has indicated it will provide EE tips and a Welcome Packet with educational information about EE opportunities, this does not mean that a customer will implement any of the provided ideas.

Further, the Program is simply a billing option. Any reduction in energy use is an ancillary result and entirely in question at this time. Additionally, a Demand Side Management ("DSM") program must be shown to be cost effective and costs associated with a DSM program can be collected through the Demand Side Management Adjustment Charge

("DSMAC"). This Program has not been shown to be cost effective and TEP is planning to collect the costs for this proposed Program from those customers who participate in the Program.

Q. TEP is requesting a waiver from A.C.C. R14-2-211 as part of its Program. Does Staff believe such a request is appropriate?

A. Yes. R14-2-211 rules address Termination of Service. Specifically, TEP is requesting that a Prepay customer not receive a written disconnect notice as required under R14-2-211(D). TEP is requesting that in lieu of a written notice, customers would receive a No Credit Disconnect alert via their choice of communications (phone, email or text) no less than four hours before the actual disconnection. Designed as such, TEP's proposed Program will function in "real time". R14-2-211(E)(1) requires a written notice to be given to the customer at least five days in advance of termination. Clearly, this is not functional under the proposed Program. As TEP is not requesting to eliminate customer notices but simply to replace them with a notice type more in line with the technological tools proposed for this Program, Staff recommends the Commission grant TEP's waiver request in this instance.

Q. In response to Staff DR STF 17.38, TEP provided a copy of its proposed Prepay Service Agreement ("Agreement"). After review of this document, does Staff have any requested changes?

A. Yes. Staff believes the following modifications to the Agreement should be made by TEP for the following section numbers:

9. Eliminate this section. Staff believes TEP should allow Lifeline customers to participate in its Program.

13. TEP indicates in testimony that it will deliver balance alerts to customers at customer-selected thresholds and a daily alert when a prefunded energy balance falls to $19 and below. This information should be added to this section to help clarify when an alert will be delivered.

20. Eliminate this section. A Prepay account closed to nonpayment is an account with no balance of funds. Therefore, there will be no outstanding balance.

Factoring in Staff's suggested changes to the Agreement, along with a number of typos and grammatical errors in the proposed Agreement, Staff requests that prior to the implementation of the Program, TEP submit its Agreement to Staff for final analysis, review and approval.

Q. In Section 3 of the Agreement, TEP indicates that to "activate a Prepay account, the customer must pay a required nonrefundable Service Establishment Fee". Does Staff believe this is appropriate?

A. Not at this time. Staff is concerned the "required nonrefundable Service Establishment Fee" may be a possible substitute for a service security deposit. Staff also notes there is no value assigned to this fee, it does not appear to be listed in the proposed Tariff nor is there any cost explanation for why this fee would be assessed on Prepay customers.

Q. While the initial testimony of Ms. Denise Smith stated "The Prepay tariff is a stand-alone tariff exclusive of certain other pricing options", TEP has indicated to Staff that it would be willing to create a Prepay tariff that would include Lifeline customers by dividing the Lifeline rate by (30) thirty days. Does Staff agree with this proposal?

A. Yes. Prepay programs across all industries are often selected by low-income end users as a convenient way to avoid security deposits. TEP customers receiving a Lifeline credit should have the opportunity to use the Program without having to move off the Lifeline program.

Q. Is Staff in agreement with the rates and charges included in TEP's proposed Prepay tariff?

A. No. Staff cannot support the proposed rates and charges at this time. Staff is still reviewing the rates and charges and reserves the right to address them in surrebuttal testimony.

Q. TEP has indicated in its response to Staff DR STF 17.20 that it has requested, in this Rate Case, the "partial socialization of credit and convenience fees to achieve a $1 per transaction fee for the payments rate for credit card transactions and the convenience of local retail channels." Does Staff agree with this effort in regards to its effect on Prepay customers?

A. No. Staff's response to the socialization request is clearly spelled out on pages 33 and 34 of the Redacted Direct Testimony of Donna H. Mullinax, filed June 3, 2016. However, as a $3.50 per transaction fee can be excessive and a burden on a Prepay customer, Staff believes TEP should clearly indicate in its Prepay Service Agreement that a customer could be subject to an additional per payment fee of up to whatever the highest convenience fee is in place. The Agreement should be periodically updated to reflect this amount as it, or if it, changes.

COMPANY REQUESTED COMPLIANCE ITEMS TO BE ELIMINATED

Q. TEP has requested to be relieved of compliance with certain Retail Electric Competition Rules. Does Staff believe TEP should be granted this request?

A. Yes. TEP has requested to be relieved of compliance with the following Retail Electric Competition Rules:

- Systems Benefit Charge Filing (R14-2-1608 (A))
- Annual Electric Competition Filing (R14-2-1613 (A) and (B))
- Annual Consumer Information Label (R14-2-1617 (A), (C), (D) and (G))
- Annual Disclosure Report (R14-2-1617 (G) and (E))

TEP based its request on the fact that these rules are not relevant as there is no electric competition in Arizona at this time and significant portions of the ACC Retail Electric Competition Rules were vacated by the "Phelps Dodge decision":[6]

Staff recommends that the requirements for the filings listed above be suspended for TEP until further order of the Commission.

Q. TEP has requested to be relieved of the requirement that it file an Annual Update to its Electric Load Curtailment Plan as required by Decision No. 66034, dated July 3, 2003. Does Staff believe TEP should be granted this request?

A. No. TEP states this filing should not be necessary unless the Plan is being modified. An Electric Load Curtailment Plan is set in place by Commission Rule R14-2-208(E) in order for the Commission to stay informed of an electric utility's procedures for handling severe supply shortages or service curtailments in the event of an emergency. While Staff has no reason to

[6]Phelps Dodge Corp v. Arizona Electric Power Cooperative, No. 1 CA-CV 01-0068, 2004 WL 117253 (Ariz. Ct. App. 27, 2004)

doubt that TEP, as it indicated to Staff, would file an update in the event of a change to its Plan, Staff is of the opinion that the Commission should always be in a position to be able to refer to the latest information in the event of an emergency, even if that information has not recently changed significantly.

However, during its analysis of this TEP request, Staff noted that TEP was filing an annual report indicating that no curtailments had occurred in the previous year. In Decision No. 66034, TEP was ordered to file a detailed curtailment report the next business day after a curtailment had occurred and not annually. Once Staff brought this to the attention of TEP, TEP indicated it would discontinue such annual filings. Staff believes this is appropriate.

Q. TEP has requested to be relieved of the requirement that it file a report every (5) five years listing potential improvements to Springerville Unit 4 that reduce emissions and costs associated with the improvements as ordered by Decision No. 65347, dated November 1, 2002. Does Staff believe TEP should be granted this request?

A. TEP stated this filing should not be necessary as Unit 4 is an unregulated, non-jurisdictional asset. Staff's analysis revealed that in Decision No. 65347, at Finding of Fact No. 66, the requirement described was for Units 1 and 2, not 4. In response to a Staff Data Request, TEP stated the request for elimination of this report should have been for Units 1 and 2. Staff then queried TEP as to whether or not the reason stated in the original request remained the same or if that reason had changed. TEP responded that: "Since the adoption of Decision No. 65347 (November 1, 2002), there has been substantial activity at the federal level regarding various emission standards, including the adoption of the Clean Power Plan. As a result, there is increased scrutiny of coal-fired power plant emissions at the federal level. Preparing the report is a costly endeavor". In addition, TEP now has an Environmental Compliance Adjustor through which for the Commission can track and review certain

environmental compliance investments by TEP each year. Staff agrees that the requirement to file a report every five years, pursuant to Decision No. 65347, is no longer needed.

Q. TEP has requested to be relieved of the requirement that it file an Annual Cost Containment Report required initially by Decision No. 59594, dated March 29, 1996. Does Staff believe TEP should be granted this request?

A. Yes. TEP states the prudency of TEP costs is reviewed by the Commission in rate cases. Since TEP has had some rate cases since Decision No. 59594, the Annual Cost Containment Report is no longer needed.

Q. TEP has requested to be relieved of the requirement that it file an Annual Estimated First or Final Bill Report as required by Decision No. 64180, dated October 30, 2001. Does Staff believe TEP should be granted this request?

A. No. TEP states that this compliance requirement involves tracking a waiver of A.A.C. R14-2-210 which has been in place for years without incident and has been reported as part of the Commission's Electric Competition Rules reporting requirements. In Decision No. 64180, TEP was granted a waiver from A.A.C. R14-2-210-(A)(5)(b) and (c) which, respectively, state that a utility or billing entity may not render a bill based on estimated usage if the bill would be the customer's first or final bill for service or the customer is a direct-access customer requiring load data. Contingent on receiving these waivers, TEP was ordered to file an Annual Estimated First or Final Bill Report indicating the number of customers who received a bill based on estimated reads of this nature along with the reason why an actual read could not be obtained. Staff believes TEP wants to keep these waivers so, as a result, does not recommend granting this TEP request.

Q. TEP has requested to be relieved of the requirement that it file a Full Decoupling Report in connection with its Lost Fixed Cost Recovery ("LFCR") annual adjustment as required by Decision No. 73912, dated June 27, 2013. Does Staff believe TEP should be granted this request?

A. TEP states that the Commission has approved a partial decoupling mechanism for TEP (the LFCR), should consider information related to full decoupling and other rate design issues in a rate case at which time TEP can then provide the information, and the current requirement is unnecessary and increases workload for TEP. Staff is generally in support of this request. If TEP has no intention of asking for full decoupling, Staff recommends the Commission eliminate this reporting requirement for TEP.

Q. TEP has requested to be relieved of the requirement that it file an Annual Letter of TEP's Code of Conduct as required by Decision No. 62767, dated August 2, 2000. Does Staff believe TEP should be granted this request?

A. Yes. TEP states this requirement was related to electric competition and has been superseded by TEP's new Code of Conduct, which was approved in Decision No. 75033, dated April 23, 2015. Decision No. 75033 approved a UNS Energy Corporation Code of Conduct. This Code of Conduct is applicable to the affiliates of UNS Energy Corporation, one of which is TEP. Finding of Fact No. 1 indicates this approved Code of Conduct "updates UNS Energy's previously approved Code of Conduct". As this updated Code of Conduct does not include Reporting Requirements, it is reasonable to conclude the Reporting Requirement requiring TEP to file an Annual Report listing all "Extraordinary Circumstances excusing TEP's compliance" with the Code of Conduct approved by Decision No. 62767 is no longer in effect.

Q. TEP has requested to be relieved of the requirement that it file an Annual Summer Preparedness Report for the Cyprus Sierrita substation Certificate of Environmental Compatibility ("CEC") as required by Decision No. 69680, dated June 28, 2007. Does Staff believe TEP should be granted this request?

A. Yes. In Decision No. 69680, TEP was ordered to submit annually a summer preparedness report that documented the ability of TEP's Green Valley area 46 kV system to timely restore service to all customers served from the Green Valley substation and Canoa Ranch Substation following outage of the 138 kV South to the Green Valley line outage (Condition 4(a)). This condition was to remain in effect until a new 138 kV transmission line built by TEP from South Substation to Cyprus Sierrita Substation with an interim interconnection at Green Valley Substation become operational. On June 27, 2013, in Docket No. L-00000C-95-0084, TEP filed a Notice of Completion of Certificated Project in which it stated that the construction of the 138 kV transmission line had been completed in its entirety and energized as of June 25, 2013. Staff believes that given the construction of the line has been completed, the reporting requirement is no longer in effect and TEP's relief request in this instance should be granted.

Q. TEP has requested to be relieved of the requirement that it file an Annual Sign Replacement Report for the Cyprus Sierrita substation CEC as required by Decision No. 69680, dated June 28, 2007. Does Staff believe TEP should be granted this request?

A. Yes. In Decision No. 69680, TEP was ordered to submit annually a Sign Placement report that documented the location of signs in public rights-of-way giving notice of the construction of the 138 kV transmission line built by TEP from South Substation to Cyprus Sierrita Substation in what was referred to as the "Phase Two" corridor in the CEC. On June 27, 2013, in Docket No. L-00000C-95-0084, TEP filed a Notice of Completion of

Certificated Project in which it stated that the construction of the 138 kV transmission line had been completed in its entirety and energized as of June 25, 2013. Staff believes that given the construction of the line has been completed, the reporting requirement is no longer needed and TEP's relief request in this instance should be granted.

Q. TEP has requested that UNS Electric, Inc. be relieved of the requirement that it file an Annual Self-Certification Letter identifying progress made with the conditions set out in the CEC for the Vail substation to the Valencia substation as required by Decision No. 71282. Does Staff believe TEP should be granted this request?

A. No. As this requirement pertains to UNS Electric, not TEP, Staff believes this request should be made by UNS Electric.

Q. TEP has requested to be relieved of the requirement that it file an Annual Self-Certification Letter identifying which conditions have been met in the CEC authorizing construction of a double circuit, 345 kV transmission line running from TEP's South 345 kV Substation to a proposed TEP Gateway Substation in Nogales, Arizona in Santa Cruz County with a 115 kV interconnection to the 115 kV Valencia Substation and 345 kV line to the international border as required by Decision No. 64536, dated January 15, 2002. Does Staff believe TEP should be granted this request?

A. Yes. In Decision No. 73625, dated December 12, 2011, issued in response to the Seventh Biennial Transmission Assessment, the Staff recommendation to suspend efforts to upgrade the reliability to a continuity of service and new transmission construction for Santa Cruz County due to the high cost of capital upgrades was adopted in the ordering language. Therefore, TEP's relief request in this instance should be granted.

Q. TEP has requested that it be relieved of the requirement to develop a data base of existing renewable energy resources within its service area within six months from the effective date (June 1, 1994) of Decision No. 58643, revise it annually and submit to Staff each year as part of the historical data filings required under Integrated Resource Planning ("IRP") rules (R14-2-703 (A) and (B)). Does Staff believe TEP should be granted this request?

A. Yes. TEP states that this requirement is moot as it derives from a 1993 Decision based on the previous version of the IRP rules which were subsequently suspended and then superseded in 2010. Additionally, similar information is being provided in accordance with current IRP rules. TEP's Renewable Energy Resources are detailed in its most recent IRP Plan filing, dated April 1, 2014, in Docket No. E-00000V-13-0070.

SUMMARY OF RECOMMENDATIONS

Q. What are Staff's Recommendations in the testimony presented here?

A. Regarding TEP's proposed Prepay Metering Program, Staff recommends the following:

- The Program be approved as a Pilot Program for at least twenty-four months.
- The Program exclude customers relying on an electrical device for medical survival.
- The Program not be included in TEP's Energy Efficiency portfolio.
- TEP receive a waiver from providing a written disconnect notice as required under R14-2-211(D) for the purposes of this Program.
- TEP Lifeline customers be allowed to participate in the Program.
- TEP modify its Prepay Service Agreement in accordance with Staff's recommendations and file it with Staff for analysis, review and approval prior to the implementation of the Program.
- The rates and charges may need to be revised, pending Staff review.

Regarding TEP's request to be relieved of certain compliance requirements, Staff recommends the following:

- The following Retail Electric Competition Rules be suspended until further order of the Commission:
  - Systems Benefit Charge Filing (R14-2-1608 (A))
  - Annual Electric Competition Filing (R14-2-1613 (A) and (B))
  - Annual Consumer Information Label (R14-2-1617 (A), (C), (D) and (G))
  - Annual Disclosure Report (R14-2-1617 (G) and (E))

- TEP continue to file an Annual Update to its Electric Load Curtailment Plan as required by Decision No. 66034.

- TEP be relieved of the requirement that it file a report every (5) five years listing potential improvements to Springerville Units 1 and 2 that reduce emissions and costs associated with the improvements as ordered by Decision No. 65347, dated November 1, 2002.

- TEP be relieved of the requirement that it file an Annual Cost Containment Report required initially by Decision No. 59594.

- TEP continue to file an Annual Estimated First or Final Bill Report as required by Decision No. 64180.

- TEP be relieved of the requirement that it file a Full Decoupling Report in connection with its LFCR annual adjustment as required by Decision No. 73912.

- TEP be relieved of the requirement that it file an Annual Letter of TEP's Code of Conduct as required by Decision No. 62767.

- TEP be relieved of the requirement that it file an Annual Summer Preparedness Report for the Cyprus Sierrita substation CEC as required by Decision No. 69680.

- TEP be relieved of the requirement that it file an Annual Sign Replacement Report for the Cyprus Sierrita substation CEC as required by Decision No. 69680.

- UNS Electric not be relieved of the requirement that it file an Annual Self-Certification Letter identifying progress made with the conditions set out in the CEC for the Vail substation to the Valencia substation as required by Decision No. 71282.

- TEP be relieved of the requirement that it file an Annual Self-Certification Letter identifying which conditions have been met in the CEC authorizing construction of a double circuit, 345 kV transmission line running from TEP's South 345 kV Substation to a proposed TEP Gateway Substation in Nogales, Arizona in Santa Cruz County with a 115 kV interconnection to the 115 kV Valencia Substation and 345 kV line to the international border as required by Decision No. 64536.

- TEP be relieved of the requirement to develop a data base of existing renewable energy resources within its service area within six months from the effective date (June 1, 1994) of Decision No. 58643, revise it annually and submit to Staff each year as part of the historical data filings required under IRP rules (R14-2-703 (A) and (B)).

Q. Does this conclude Staff's direct testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239

SURREBUTTAL RATE DESIGN

TESTIMONY

OF

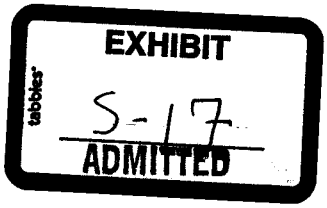
MATT CONNOLLY

EXECUTIVE CONSULTANT II

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 26, 2016



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EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NOS. E-01933A-15-0322 AND E-01933A-15-0239

The Arizona Corporation Commission Utilities Division's ("Staff") surrebuttal testimony addresses the rebuttal testimony of Tucson Electric Power Company's ("TEP") witnesses Craig Jones and Denise Smith regarding TEP's request for the implementation of an optional Prepay Metering Program.

Regarding TEP's proposed Prepay Metering Program, Staff recommends the following:

- The Program be approved as a Pilot Program for at least twenty-four months.
- If TEP proves it is able to accurately determine when a customer moves into the higher usage kWh, Staff recommends that the energy rates for the Prepay Program should equal the energy rates of the Residential Electric Service ("RES"). If TEP proves it is unable to accurately determine when a customer moves into the higher usage kWh, Staff recommends that the energy rate for the Prepay Program should equal the first tier energy rate of the RES for all kWh usage.
- The Program exclude customers relying on an electrical device for medical survival.
- The Program not be included in TEP's Energy Efficiency portfolio.
- TEP receive a waiver from providing a written disconnect notice as required under the Arizona Administrative Code § R14-2-211(D) for the purposes of this Program.
- TEP Lifeline customers be allowed to participate in the Program.
- TEP modify its Prepay Service Agreement in accordance with Staff's recommendations and file it with Staff for analysis, review and approval prior to the implementation of the Program.
- TEP should provide to Staff the third-party evaluation of the Prepay Program within (60) sixty days of the completion of the evaluation. TEP should also include its recommendation as to whether the Prepay Program should be implemented on a permanent basis, continue as a Pilot Program for an extended period of no more than an additional (24) twenty-four months, or be discontinued.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Matt Connolly. I am an Executive Consultant II employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony regarding Tucson Electric Power Company's ("TEP") request for the implementation of an optional Prepay Metering Program and its request for the elimination of certain compliance requirements.

Q. What is the scope of your surrebuttal testimony in this case?

A. My surrebuttal testimony addresses the rebuttal testimony of TEP witnesses Craig Jones and Denise Smith regarding the proposed Prepay Metering Program.

THE COMPANY REQUESTED PREPAY PROGRAM

Q. Please describe the rate changes TEP made in its proposed Prepay Program in its Rebuttal Testimony.

A. In its rebuttal testimony, TEP modified the proposed kWh rates upward. As a result, in its proposed Prepay Program, TEP changed the first Energy Delivery rate assessed in both summer and winter for the first twenty (20) kWh per day from $0.064000 to $0.065000. TEP also modified the second rate of $0.079000 which will be applied to kWh over (twenty) 20 per day to $0.084000. The Program also now proposes a $17.00 monthly basic service charge to match the proposed Basic Residential monthly service charge. Combining the $17.00 with the proposed $5 equipment and systems adders brings the total to $22.00.

Q. Has Staff revised its recommendations regarding the monthly customer charge and the energy rate?

A. Yes. In the surrebuttal testimony of Mr. Howard Solganick, he proposes to reduce the monthly customer charge for the standard residential rate schedule from Staff's initial recommendation from $17.00 to $15.00. In addition, Mr. Solganick has revised the first tier energy rate to $0.064008 and the second tier energy rate to $0.080588. As a result, for the Prepay Program, Staff now recommends the customer charge and energy rate be consistent with Mr. Solganick's proposed changes.

Q. Does Staff have any concerns with these proposed Prepay Program energy rates?

A. Yes. Staff has some concern about the application of the current TEP proposed energy rates. TEP states that although they can track daily energy consumption for a Prepay customer, TEP is unable to determine when in the daily billing cycle a Prepay customer would move from one energy rate tier to the next. Therefore, TEP is proposing to use a weighted average of the Residential Electric Service ("RES") energy rates in order to calculate the first tier energy rate for the Prepay Program. The energy rate for the second tier of the Prepay Program would be equal to the proposed second tier RES energy rate. As a result, the current proposed first tier energy rate for the Prepay Program is slightly higher than the current proposed first tier energy rate for RES.

Q. Does Staff have an alternate proposal regarding the Prepay Program energy rates?

A. Yes. Although TEP states it may be difficult to track when a Prepay customer moves into the next energy rate tier, Staff believes there should be no difference in the energy rates charged in the Prepay Program and the RES especially as this would be a Pilot Program. In addition, Staff is unaware of any other regulated utility with a prepay program that employs energy rates that differ from its residential energy rates. Further, using the same energy rates

for the RES and the Prepay Program provides the opportunity to reduce TEP customer confusion. TEP will have the opportunity to revisit its Prepay Program rate structure at the end of this Pilot Program. Therefore, if TEP proves it is able to accurately determine when a customer moves into the higher usage kWh, Staff recommends that the energy rates for the Prepay Program should equal the energy rates of the RES. However, if TEP proves it is unable to accurately determine when a customer moves into the higher usage kWh, Staff recommends that the energy rate for the Prepay Program should equal the first tier energy rate of the RES for all kWh usage.

Q. As mentioned above, TEP's Prepay Plan will include an additional $5 adder to cover the costs of equipment and system implementations for the Prepay Program. Is Staff in support of these additional fees?

A. Yes. TEP states that there are three monthly fees with a combined total of $5 that are applicable to the Prepay Program due to the unique requirements of a Prepay customer. A $2 fee to cover the cost of the cellular system required by the meter to facilitate on demand disconnection and reconnection, a $1 fee for partial recovery of the cost of the meter to be installed at the customer's premise and a $2 fee as an incremental charge towards the cost of upgrading the data management system and billing interface required to provide the Prepay service. As previously testified, Staff does not have any reason to dispute the amount and application of these fees. Staff was also unable to determine whether or not the amount of these fees reflects the true costs of implementation and use and believes these fees are only estimates at this time. Therefore, these costs should be tracked under the Pilot Program.

Q. TEP witness Ms. Denise Smith indicates in her Rebuttal testimony that TEP continues to plan to include the Prepay Program as part of its 2016 Energy Efficiency ("EE") portfolio. Does Staff continue to have any objections over such an inclusion?

A. Yes. Staff does not change in its belief that the Program is a billing option and not an energy efficiency program. The perceived conservation of energy may be simply as a result of customers who run out of money and are disconnected. Ms. Smith appears to signal that implementation of the data management tools TEP will make available to Prepay customers in order to manage their energy usage won't take place unless the proposed Prepay Program is approved as part of TEP's EE portfolio. However, as Staff is under the impression that these are the same tools for which TEP is already proposing to charge each Prepay customer an additional $2 per month, Staff is not swayed by this point. Staff is open to the possibility that Prepay customers may be willing to modify their energy use with conservation efforts but believes before TEP submits the proposed Prepay Program as one if its EE programs, it use the Staff proposed twenty-four month Pilot period to generate data proving Prepay customers are voluntarily using the Program to reduce energy usage.

Q. TEP witness Ms. Denise Smith indicates in her Rebuttal testimony that TEP continues to plan to include Section 20 in its Prepay Service Agreement which addresses the closing of Prepay accounts due to nonpayment. Does Staff continue to have any objections to this?

A. No.

Q. In the Rebuttal Testimony of TEP witness Craig Jones, he reiterates that all customers will be paying a Service Establishment Fee, including Prepay customers. Does Staff continue to have an objection to this?

A. No. In discussion with Staff, TEP indicated that the Service Establishment Fee would only apply to new TEP customers who elect to use the Prepay Program and would not apply to existing customers who move to the Prepay Program. However, Staff requests that the amount of the Service Establishment Fee (currently at $32.00 and proposed at $38.00) determined in this rate case be clearly indicated in the Prepay Service Agreement as a separate and additional charge for a new customer in addition to the at least $20.00 to establish a Program balance, and that TEP ensure all Prepay customers are informed in advance of program election.

Q. Does Staff have any new recommendations regarding TEP's Prepay Program?

A. As mentioned in my Direct Testimony, TEP is proposing a third-party evaluation of the Prepay Program not less than 24 months after (i) the launch of customer enrollment, and (ii) two successive "high bill" seasons. At the end of the 24 month period, TEP should provide to Staff the third-party evaluation of the Prepay Program. TEP should also include its recommendation as to whether the Prepay Program should be implemented on a permanent basis, continue as a Pilot Program for an extended period of no more than an additional (24) twenty-four months, or be discontinued.

SUMMARY OF RECOMMENDATIONS

Q. What are Staff's Recommendations in the surrebuttal testimony presented here?

A. Regarding TEP's proposed Prepay Metering Program, Staff recommends the following:

- The Program be approved as a Pilot Program for at least twenty-four months.

- If TEP proves it is able to accurately determine when a customer moves into the higher usage kWh, Staff recommends that the energy rates for the Prepay Program should equal the energy rates of the RES. If TEP proves it is unable to accurately determine when a customer moves into the higher usage kWh, Staff recommends that the energy rate for the Prepay Program should equal the first tier energy rate of the RES for all kWh usage.
- The Program exclude customers relying on an electrical device for medical survival.
- The Program not be included in TEP's Energy Efficiency portfolio.
- TEP receive a waiver from providing a written disconnect notice as required under Arizona Administrative Code § R14-2-211(D) for the purposes of this Program.
- TEP Lifeline customers be allowed to participate in the Program.
- TEP modify its Prepay Service Agreement in accordance with Staff's recommendations and file it with Staff for analysis, review and approval prior to the implementation of the Program.
- TEP should provide to Staff the third-party evaluation of the Prepay Program within (60) sixty days of the completion of the evaluation. TEP should also include its recommendation as to whether the Prepay Program should be implemented on a permanent basis, continue as a Pilot Program for an extended period of no more than the next rate case decision, or be discontinued.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.