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Transcript Exhibit(s)

Docket #(s): E-04204A-15-0142

Exhibit #: UNSE - 31 - 41, 43 - 44

Part 8 of 8

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
SUSAN BITTER SMITH - CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

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-______

EXHIBIT UNSE-31 admitted

Direct Testimony of

Craig A. Jones

on Behalf of

UNS Electric, Inc.

May 5, 2015

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Exhibits

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Craig A. Jones. My business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am employed by Tucson Electric Power Company ("TEP"), a wholly-owned subsidiary of UNS Energy Corporation ("UNS Energy") as the Manager of Pricing. As the Manager of Pricing, I am responsible for various rate-related matters including monitoring and coordinating the determination of customer pricing options with any necessary support to justify the creation of the various rate structures for all the regulated subsidiaries of UNS Energy, including TEP, UNS Electric, Inc. ("UNS Electric" or the "Company") and UNS Gas, Inc. ("UNS Gas"). This includes overseeing the development of the cost-of-service analysis and rate design in general rate cases.

Q. Please describe your educational background.

A. I graduated from the University of Missouri Columbia in December 1980 with a Bachelor of Science Degree in Agricultural Engineering. In May 1981, I received a Bachelor of Science Degree in Agricultural Mechanization. I have completed much of the course work required for a Master's Degree in Agricultural Engineering at the University of Missouri Columbia. I am qualified as an Engineer-in-Training under the laws of the State of Missouri.

Q. Please describe your professional background and experience.

A. In February 1983, I joined the Staff of the Missouri Public Service Commission as a Rate Engineer. My responsibilities included analyzing and making recommendations relating to purchased gas adjustment filings, actual cost adjustment filings, rate cases, certificate of service applications, intrastate pipeline applications and applications to establish new local distribution systems. I left the Missouri Public Service Commission in December 1994 to take a position with the New York State Electric and Gas Corporation ("NYSEG"). My responsibilities at NYSEG included establishing prices to be used in "repackaged" contract offerings, training co-workers and end-users with respect to the application of new rates and service concepts, and complying with regulatory filing requirements, including the calculation and filing of the monthly gas cost adjustment filings with the New York Public Service Commission.

I left NYSEG in April 1998 to take a position as Rates Manager with Citizens Energy Group (formerly Citizens Gas & Coke Utility) ("Citizens") in Indianapolis, Indiana. In March 2004, I was promoted to Manager Rates and Regulatory Affairs. I was responsible for various rate-related matters associated with both the natural gas and steam utilities operated by Citizens, including the annual filings for approval of a fuel cost adjustment for the steam utility and the development of the monthly gas cost adjustment filings, various miscellaneous tariff filings, special contracts, and numerous other rate-related activities for the gas and steam utilities, including cost of service and rate design in general rate cases.

In November 2009, I left my position at Citizens and joined TEP as the Manager of Pricing. Since joining TEP, I have provided pre-filed direct testimony and live testimony in the UNS Gas 2011 general rate case (Docket No. G-04204A-11-0158, Decision No. 73142), and pre-filed testimony in TEP's last general rate case (Docket No. E-01933A-12-0291) and UNS Electric's 2012 general rate case (Docket No. E-04204A-12-0504, Decision No. 74235). I have actively participated in the Arizona Corporation Commission's ("Commission") Decoupling Workshops, Line Extension reviews and the filing of TEP's Community Solar tariff and other Pricing and Regulatory activities.

Q Have you previously testified before any other regulatory agencies?

A. Yes. I testified before Indiana Public Service Commission on numerous occasions, including in Cause Nos. 41969-FAC01-FAC15, 41969-FAC03(S1), 41969-FAC06(S1), 41605, 41824, 42578, 42726, 42767, 43025, 43463 37399-GCA68, 37399-GCA68(S1), 37399-GCA69, and 37399-GCA77. I also testified before the Missouri Public Service Commission on several occasions regarding rates, tariffs, and certificate applications.

Q. Are you sponsoring any schedules?

A. I am sponsoring the "G" and "H" Schedules, which summarize the class cost-of-service study ("CCOSS"), rate design, and proof of revenue in this proceeding. Two pages of the Schedule H have been redacted because they contain confidential customer-specific information and will be provided pursuant to the terms of the protective agreement that will be entered into in this docket.

Q. Could you please summarize your Direct Testimony?

A. First, I detail UNS Electric's Class Cost of Service Study ("CCOSS"). This study is necessary in order to determine an appropriate total cost to serve each class. The goal of the CCOSS is to determine fair cost allocation and rate design among the customer classes based on the principle of cost causation. Ascertaining which classes are responsible for which costs is the bedrock of designing rates. The Company's objective, by undertaking a CCOSS, is to confirm that proposed rates generate revenue that recover costs and provide for a reasonable return on investment per customer class.

As part of UNS Electric's CCOSS, I directed the development of an embedded cost study and a marginal cost study for the Company. Both studies are useful in developing rate designs that support and reflect valid price signals. The results of the embedded cost study provide important guidance for the class allocation of revenues; while the embedded cost and marginal cost studies, taken together, help determine the level of specific charges to establish just and reasonable rates. For the embedded cost study, the Company has chosen the Average and Excess method to allocate demand costs, a commonly-accepted methodology used in the industry, including Arizona Public Service Company ("APS"). By contrast, the Company's marginal cost study is a forward-looking study that focuses on the change in costs associated with a small change in the number of customers added to the system – or the cost to replace the current customer related infrastructure to continue service to an existing customer. As a result, the Company can propose rates designed to encourage efficient use of the UNS Electric system and to establish customer charges that send the right price signals to customers.

Second, I describe the Company's proposed rate design, including modifying existing rates to move toward parity and recover costs in a more equitable manner from all similarly situated customers – by shifting more of the fixed costs into fixed-rate components and to create rate classes that contain a more realistic grouping of customers. I describe how UNS Electric's proposed rate design will also better align the Commission's policies with the Company's need for fixed cost recovery, as well as reduce existing cross-subsidies within and between customer classes. To meet these objectives, and in light of the CCOSS results, my testimony explains how UNS Electric proposes a lower percentage rate increase for classes presently paying significantly more than the system-average return on rate base, and a higher percentage rate increase for classes presently paying significantly less than the system average return on rate base. I also detail additional factors focused on in designing rates – including billing determinants, ratchets, and consistency. My testimony also explains that the resulting bill impact is reasonable and consistent with the gradualism principle. Additionally, I set forth the bill impacts of these changes.

My testimony also describes UNS Electric's proposal to increase the monthly basic service charges to levels that better match the minimum cost to serve the customer – including incorporating demand-related costs for those classes without a demand charge. The proposed rate design changes are needed to send customers more accurate price signals. With better price signals to the customers and more appropriate fixed cost recovery for the utility the environment will be much more conducive to the promotion of energy efficiency ("EE") and distributed generation ("DG").

My testimony also addresses other rate design changes including: (1) elimination of the third rate tier in the residential Rate RES-01; (2) the addition of a second tier to comparable time-of-use ("TOU") Rate RES-01 TOU (incenting customers to move their consumption from on-peak hours to off-peak hours in order to generate savings on their bills); (3) establishment of a charge for those customers who do not want an automated meter installed; (4) establishment of a new Medium General Service ("MGS") class; (5) changes to the demand charge for certain classes; (6) modification of the Large Power Service ("LPS") class so that it contains only customers taking service at transmission level voltage; (7) revising the Community Solar rate; (8) freezing the current Interruptible Tariff and proposing another interruptible option that provides more benefit to the system.

In short, the Company seeks to modernize and update its rate design to address: (i) declining usage per customer; (ii) low-use/no-use customers paying an equitable share of the fixed costs to operate and maintain the UNS Electric grid; and (iii) lost-fixed cost revenues associated with energy efficiency and distributed generation.

<u>Third</u>, I address Customer Assistance Residential Energy Support Program ("CARES") rates. The Company proposes to simplify the CARES rate by offering a single uniform discount. The modifications would reduce the two existing tariffs which contains six multi-leveled percentage discount variations and two fixed discount variations of CARES rates

down to a flat $10.00 per month discount (limited to a reduction of the bill down to zero dollars.) The Company would modify the current CARES customer's rates and freeze the standard CARES rate in the same manner as the frozen CARES-Medical rate. UNS Electric also proposes to eliminate the exclusion of CARES rates from the Demand Side Management ("DSM") surcharges.

Fourth, I discuss the Company's proposed buy-through rider, which it is proposing as required under the settlement agreement involving Fortis Inc.'s ("Fortis") acquisition of UNS Energy. To be clear, UNS Electric is merely presenting this experimental rider in order to comply with the settlement agreement and is neither endorsing the concept nor approval of this specific tariff. Essentially, the Large Power Service ("LPS") customer would select a wholesale generation service provider, who would sell power to the Company on the customer's behalf and delivered to one or more of the Company's points of delivery for wholesale power. The Company would then take title to the power and provide it to the customer in exchange for payment in accordance with the power supply agreement, the terms of experimental rider, and other program provisions. The customer would not be exempt from any of the charges and adjustments in the retail rate schedule (except for Power Supply Charges and the purchased power and fuel adjustment clause ("PPFAC").) Further, the tariff would only be available to select LPS customers, only up to 10 MW and for a maximum of four years from the effective date of the rate rider schedule.

Fifth, I provide the "all-in" bill impact comparison by class by using "typical" usage amounts for each rate class. I detail the methodology used to develop these comparisons, which provides a much more accurate comparison of current rates to proposed rates beyond what is provided in the "H" schedules. This methodology takes into account the increases associated with the rate design changes, the proposed increase in base rates and updated fuel costs. It also considers the changes resulting from including transmission related expenses that are currently being recovered through the TCA, into base rates and the equivalent offset associated with resetting of the TCA. In addition to the mentioned changes it considers the proposed credit resulting from the deferred savings accumulated in accordance with the Deferred Accounting Order associated with the Company's purchase of a 25% interest in Gila River Power Plant Unit 3. All of these items will impact a customer's bill on or around the effective date of the rates requested herein and should be considered when evaluating the impact of the Company's request on a customer.

Sixth, I address the weather normalization and customer annualization adjustments. Both of these adjustments reflect test year billing determinants under normal weather and year-end customer levels, respectively. For the weather normalization adjustment, I am proposing to use a more refined method that produces forecasts that are more closely aligned with actual results (what I call the "Average Temperature" method). Regarding the customer annualization adjustment, the Company proposes to use the same method that has been approved by this Commission in prior electric rate cases. I also summarize the Company's proposed transmission expense adjustment, and the adjustments and additions regarding miscellaneous service charges.

Finally, I describe UNS Electric's proposed modifications to the PPFAC and the LFCR. Regarding the PPFAC, the Company proposes a single percentage-based adjustment applicable to all rate classes and based on the monthly change in total annual fuel cost compared to the annual fuel cost approved in this proceeding – while also changing the rate band to 1% and adding a "Base Rate Annual Adjustment." For the LFCR, the Company proposes to allow recovery of lost fixed costs attributable to generation and the full recovery of lost demand revenues. Generation costs are significant, unavoidable and necessary. Because the calculation of demand-related losses specifically identifies the actual amount of offset to the customer's peak demand, only allowing 50% of lost demand revenues does not reflect the actual value of demand-related losses.

II. COST OF SERVICE ANALYSIS.

Q. What is the purpose of performing cost of service studies and how is it beneficial to customers?

A. The cost of service study is the core foundation in developing just and reasonable rates. Once the Company's revenue requirement is calculated, the next step is determining how and from whom it should be recovered.

A properly performed CCOSS analyzes all costs and services provided to each of the primary rate classes. The CCOSS also provides a guide as to how those costs should be recovered from each rate class. As I will discuss later in my testimony, there are multiple ways of determining how costs should be allocated. While each party representing a specific group of customers may have an opinion on how those costs should be split between the classes, UNS Electric is focused on allocating the costs as fairly as possible. Fair cost allocation is based on the principle of cost causation. This principle has been referred to as the gold standard of cost of service. Equitably allocating costs between the classes protects all customer classes and creates rates that attempt to assign customers the actual cost of serving them. The Company's goal is to create fair and equitable rates for all customer classes under sound Cost-of-Service and Rate Design principles.

Q. Please discuss the concept of cost of service as a tool for ratemaking.

A. The process of developing rates relies on cost of service for establishing both the revenue level by class and the design of rates. By understanding how costs are caused and establishing rates to reflect cost causation, the important principle of matching costs with revenues under new rates will be satisfied. While CCOSS are a great tool to use in this process, sometimes technology and available data can constrain the overall outcome of the CCOSS.

Q. How does technology and available data limit the usefulness of the CCOSS?

A. CCOSS attempts to match costs with cost causation. However, it must be recognized that the best possible matching may be constrained by the ability to measure all of the needed elements of cost causation with the current meter and billing technologies. As technology advances in both the areas of cost causation and metering to track those costs, one must also recognize the temporary nature of that constraint. Thus, it is important to begin to modify rate designs so that there is a reasonable transition to new, more efficient rates that are enabled by new technology.

Q. What is the objective of the CCOSS?

A. Based on allocated costs, the goal is to confirm which present and proposed rates generate revenues that recover appropriate levels of costs per customer class. The term "cost" covers both expenses (including taxes) and the return on the Company's investment. The total cost to serve a particular class varies depending on the customers' individual and combined consumption characteristics, installed facilities, labor, and other capital needed to reliably and safely serve customers in the class.

If the proposed rates produce customer class revenues resulting in each class generating revenues sufficient to earn a return on plant that matches the overall return on invested capital, "parity" has been reached. This is typically characterized by a "return index" (actual return/ required return) of one (100%) for each class. The CCOSS is designed to clearly present the costs and the allocation factors applied to the costs. The cost model also includes sections summarizing costs, a list of the allocation factors, and a revenue requirements summary. The "G" Schedules of the filing are assembled using the results of the CCOSS. Please refer to Schedule G-2 –Summary at Proposed Rates to see the results of the Company's CCOSS calculations.

Although existing circumstances may preclude reaching "parity", the goal should be to use the results of the CCOSS to minimize cross subsidies.

Q. **Please summarize the types of CCOSS used in allocating revenue and designing electric rates.**

A. Cost studies may be based on embedded costs or marginal cost. Embedded cost studies analyze the costs for a test year based on either the book value of accounting costs (a historical period), the estimated book value of costs for a forecasted test year or some combination of actual and forecast costs. The cost of service period is adjusted for known and measurable changes and is normalized and annualized. The cost of service used for the study is also used to determine the revenue requirement and is based on the 2014 calendar year for this filing.

Typically, embedded cost studies are used to allocate the revenue requirement between jurisdictions and classes and between customers within a class. In addition to providing information related to the allocation of revenue requirement changes among customers the CCOSS provides valuable information for rate design. A fully unbundled CCOSS provides the fully allocated costs of a detailed list of various services provided by the Company.

By contrast, marginal cost studies do not reflect actual costs but rely on estimates of the expected changes in cost associated with changes in service. Marginal cost studies are forward looking to the extent permitted by available data. Marginal cost studies are most useful for rate design when it is important to send appropriate price signals associated with demand and energy consumption by customers in a particular class. Marginal cost is also important for determining optimal seasons and time of use periods. In this case, UNS Electric is relying on information from both the embedded and the marginal cost studies for its recommendations related to rate design.

Q. Have you prepared cost studies for this case?

A. Yes. The embedded cost study for the test year has been prepared under my supervision and can be found in Schedule G submitted as part of this filing. Also prepared under my supervision is an analysis of the marginal customer costs for residential and small general service customers to support improvements in the efficiency and tracking of costs for the historic two-part rate design consisting of basic service charges and volumetric charges.

Between the marginal cost study and the embedded cost study there is sufficient information to develop a just and reasonable rate design for customers in the classes where we currently bill only a basic service charge and an energy charge. Ultimately, the ideal rate design should include a combination of demand charges, a basic service charge and time differentiated energy charges for all. This will allow the Company to convey accurate price signals to customers about the cost of those individual services they choose to purchase from UNS Electric

UNS Electric is proposing the necessary steps to improve its price signals and to transition over time to more appropriate rate design. Thus, our proposal uses (i) the results of the embedded cost study to provide important guidance for the class allocation of revenues and (ii) the embedded cost study and the marginal cost study to determine the level of specific charges that taken together create just and reasonable rates.

A. Cost of Service and Economic Theory.

Q. Please explain the importance of cost causation in developing a cost of service study.

A. Just and reasonable rates must avoid undue discrimination and must reflect the principle of "user pays," also known as "cost causation," or as I prefer to say, those who cause the costs should pay the costs. Undue discrimination occurs when customers pay significantly different amounts for the same service without good cause.

The development of cost-based rate structures permits regulatory review of the costs that are the same on average for customers in the class. I say "on average" because no two customers are exactly alike. Therefore, we determine costs and set cost-based rates for "typical" customers grouped by similar demand and usage patterns. For example, residential customers may have different service costs just based on the proximity to the distribution transformer. Typically, the customer on the same side of the street as the transformer will have a shorter service line than the customer across the street. As a result, the cost of service differs based on which side of the street the home is located.

In setting rates, we use the average cost of the two services. Once we determine the customer related costs, those costs should be recovered in the basic service charge. If those costs are not recovered in the basic service charge, then they are recovered in the volumetric charges which results in the customers with higher than average energy consumption subsidizing the customers who use less than average. The cost of service study that unbundles customer costs provides a benchmark to assess the rates to determine if they are just and reasonable and do not discriminate based on the rate design.

I am not alone in expressing this view. For example, the Rocky Mountain Institute has published a report titled "RATE DESIGN FOR THE DISTRIBUTION EDGE:

ELECTRICITY PRICING FOR A DISTRIBUTED RESOURCE FUTURE". That report, published in August of 2014, recommends full unbundling for efficient integration of distributed resources that include not only DG but conservation and DSM as well. In the executive summary the report states "...bundled, volumetric block rates—provide little or no incentive for the deployment and operation of DERs (Distributed Energy Resources) at the times and places where they can create greatest overall benefit. The perpetuation of these pricing structures in the face of ongoing improvement in DER cost and performance and increased adoption of these technologies will result in *lost opportunities for cost reduction and inefficient utilization of assets on the part of both customers and utilities*." (Emphasis added.)

It is also important to know the marginal cost because the economic concept of "subsidy free rates" means that the rate must be above marginal cost but less than stand-alone costs. In order for rates to be efficient, the concept of customers being charged for the distinct services they use is important since different customers use different services. Further, the costs of those services may be different because of the different load characteristics of customers within the same class. Both cost allocation and rate design are critical in designing efficient rates.

Q. **How have you approached the development of the cost studies?**

A. A properly developed cost of service study represents an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. Understanding cost causation requires an in-depth understanding of the planning, engineering, and operations of the utility system, as well as the basic economics of the unbundled components of the electric system. In developing both the embedded cost study and the marginal customer cost study, I have relied on input from planning, engineering and operations within the Company.

Q. Please describe the nature of utility costs.

A. The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common and joint costs[1]. In addition, utility costs may be fixed or variable.[2] Finally, utility costs exhibit significant economies of scale.[3] These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of cost studies requires an understanding of the operating characteristics of the utility system. Further, as noted above, different cost studies provide different contributions to the development of economically efficient rates and the cost causation by customer class.

Utilities are unusual in the relationship between fixed and variable costs. The only variable costs for an electric utility are the costs of fuel, purchased power, fuel handling and some limited amount of variable operating and maintenance expense ("O&M"). All other costs are fixed. The fixed costs for UNS Electric represent the sunk costs of the utility to produce and deliver electricity and provide other services to customers, such as taking energy from customers who self generate in excess of their own needs and push that excess back onto the distribution system for delivery to other customers. The portion of fixed and variable costs of the total cost of service varies among the customer classes based on the types and quantity of the services used by the customer. Currently, UNS Electric's residential rates only recover approximately 18% of the average level of fixed costs approved in the Company's last rate case as a fixed component in the rates.

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[1] Common costs occur when the fixed costs of providing service to one or more classes or the cost of providing multiple products to the same class use the same facilities and the use by one class precludes the use by another class. Joint costs occur when two or more products are produced simultaneously by the same facilities in fixed proportions. In either case, the allocation of such costs is arbitrary in a theoretical economic sense.

[2] Fixed costs do not change with the level of output, while variable costs change directly with the utility output. The vast majority of non-fuel related utility costs are fixed and do not vary with changes in load.

[3] Scale economies result in declining average cost as output increases and marginal costs are below average costs.

As a practical matter, failure to recover fixed costs in fixed charges results in unreasonable outcomes by creating subsidies both between and within the classes. It can also result in the utility recovering either more than or less than the authorized revenue requirement, based on whether consumption is higher or lower, respectively, than the levels used in the determination of base rates.

In the new mixed competitive and regulated market, traditional rate classes are no longer homogeneous. In fact the availability of self generation (particularly solar distributed generation) has created a second class of customers within the typical residential service class. Some customers remain the traditional full requirements customer using all of the bundled services of the utility while a growing number of customers have become partial requirements customers who use a variety of different services. Partial requirements customers require various utility services including standby service, supplemental service, delivery service for energy purchases and delivery services for energy sales, regulation services, power factor correction and balancing. For distribution services, the cost of serving these partial requirements customers is typically the same or higher than it was when the customer was a full requirements customer.[4] However, the self-generating customer purchases far fewer kWh and thus avoids paying for fixed distribution costs when rates recover those costs in energy charges. The table below illustrates this problem. The table presents a comparison of two residential customers with identical energy usage and delivery requirements. The customers both use an average of 900 kWh per month. One customer is a full requirements customer taking service on RES-01. The other customer is a partial requirements customer and owns a photovoltaic DG system that is sized to produce 100% of the energy the customer uses over a year. The partial requirements

[4] This is because the DG customer may require additional investments in the distribution system to provide frequency control and power factor correction for example.

customer is on a net metering tariff that allows banking and rollover of excess self-generated production.

Residential Customer Comparison	RES-01 Full Requirements Customer	RES-01 DG Customer with Net Metering
NCP kW Demand	6.30	6.30
Annual Billed kWh	10,800	133
CCOSS Customer Costs ($/customer/year)	$168.00	$168.00
Distribution Demand Cost ($/NCP kW/year)	$46.90	$46.90
Annual Customer & Distribution Costs	$463.66	$463.66
Annual Customer & Distribution Revenue	$459.03	$241.22

As this table illustrates, these two customers pay different amounts for the same distribution services. In reality, the partial requirements customer is also likely to require more services than the full requirements customer as well even though their demands are the same.

The Company is moving to a new rate design model that is designed to recognize that the distribution system is a critical and regulated component of the new market model. While distributed generation, in the form of PV solar, wind and combined heat and power ("CHP"), changes the amount of energy that must be produced by central generation, it continues to be dependent on the distribution system for many critical services.

Q. How is cost causation determined?

A. In many cases determining cost causation is as simple as asking the question of whether a particular cost changes when some potential allocation factor changes. If a factor causes costs, costs will vary with changes in that factor. For example, if the number of kWh increases, does the cost of some input such as miles of conductor increase with more kWh? Since the miles of conductor do not change with kWh either monthly or annually, energy consumption is not a cause of conductor costs. What we do know is that the number of miles of conductor increases when customers are added to the periphery of the system, thus customers are a cause of the cost. We also know that the length of conductor increases with the growth of the peak load on the conductor which may require paralleling the system, looping the system, or networking the system. It may also mean building added capacity through expanding the system to a three phase conductor. This means that some of the cost of conductors is also caused by the demand on the conductor. In any case, the factors driving the cost of conductor are customers and a measure of non-coincident peak demand. Following this logical process allows one to determine cost causation for each element of the system.

Fundamentally, performing cost of service studies is comprised of applying experience and science. The science of the process involves calculations consistent with the methods outlined in the National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual ("NARUC Manual"). The art of applying experience involves the subjective application of certain methods, in conjunction with consideration of policy objectives, regulatory case law, emerging issues, and other factors, within the framework of the regulatory process.

Q. How do you decide what type of cost you are analyzing?

A. There are three fundamental cost classifications that are the basis for cost causation: customers; demand; and energy. Essentially, all costs incurred by the utility are directly or in some cases indirectly related to one of these three factors. That is, a utility incurs costs based on (i) the number, size, geographic location and type of customers, (ii) a combination of several measures of customer demand or (iii) a measure on the energy used by customers. Within these three classifications there may be different measures of the factor based on how costs are incurred when allocation factors are developed.

The NARUC Manual identifies three fundamental methods for allocation of demand related costs: Coincident Peak ("CP") methods, Non-Coincident Peak ("NCP") methods and Average and Excess Demand ("AED") methods. Within each of these categories, there are numerous specific formulations of the methods. Further, to reflect the cost of an electric system, a complete cost of service study requires application of more than one demand category of these allocation factors. For example, class non-coincident peaks drive the allocation of part of the distribution system capacity while it is some combination of coincident peaks and demand and energy methods for generation. Within each classification category, there may be multiple specific methods. CP allocation category options include a single CP, 4 CP, 12 CP, winter/summer CP and so forth. In addition to the AED allocation method, there are a number of methods that consider both demand and energy such as peak and average, peaker methods and so forth. These methods are all described in the NARUC Manual.

In any event, the choice of methods relies on the concept of cost causation to choose the most appropriate method that best reflects those costs. NCP methods may use a variety of peaks other than the actual system peak based on the peaks of individual service classifications or individual customers. Cost causation requires the determination of the cost to serve each class of customers in a way that recognizes apparent cost responsibility and reflects the engineering and operating characteristics of the utility system. It is not unusual that a cost study includes all of the methods for allocating demand and potentially more than one of the variants of the methods.

Q. **Please explain the classification and allocation of distribution costs.**

A. There is an underlying logic to the choice of the most appropriate demand allocation factor. The system distribution plant consists of different facilities that have different cost causation factors. The reason for this is threefold. First, load diversity increases as the cost becomes more remote from the individual customer. Second, some facility cost is directly the result of the individual customer and is caused by the customer unrelated to demand. These facilities include the meter and service line. Third, other local facilities have both a customer and a demand component. Transformers are sized to meet the NCP of the customers served from a single transformer but utilities do not install every possible size of transformer. Instead, utilities use a standard set of transformer sizes and one of those is the transformer that represents the minimum size. Transformer costs exhibit significant scale economies. This means that the smallest size of transformer costs much more per kVa than larger transformers. Given the fact that utilities typically use a minimum size of transformer, the cost of the minimum size is related to a customer since every customer requires transformer capacity.[5] For transformers larger than the minimum size, the remainder of transformer cost is related to demand. The portion related to demand is based on the customers served from each transformer and represents a much smaller share of costs than the customer component. Given the proximity of the customers to transformers, there is limited diversity for transformers that may serve a few customers and no diversity if a transformer serves only one customer. Thus, transformer demand is related to the individual customer NCP. The NCP for the system based on the sum of individual customers is much higher than either the system coincident peak or the sum of the class NCPs. For facilities located close to the customer, such as transformers, secondary conductor, and secondary poles and even single phase primary conductor, both a customer component and the individual NCP allocation factor is the most appropriate. As the cost becomes more remote from the customer, it is the class NCP that drives the costs. This applies to the demand portion of primary poles and primary conductor. The substation related investment is based on the class NCP allocation factor alone. In fact, any number

[5] For larger customers, the customer may provide its own transformers or even its own substation in some case for very large customers. These distinctions are typically reflected either as credits in rates or separate rate schedules for different service classes defined based on usé of distribution facilities.

of substations peak at different times and even different seasons from the coincident peak demand of the utility.

Q. Have you considered the customer component in the CCOSS you have developed for the Company in this rate case?

A. Yes. You can see the allocation of certain costs to a mix of customer and demand as you review the allocations in Schedule G, sheet G-7 Allocations.

Q. Are all customers allocated some level of distribution costs?

A. No, except for metering related costs. Distribution costs differ based on the portion of the system used by different classes of service. In fact, some customers make no use of the distribution system at all. For example, for LPS customers there are no distribution costs allocated to the class other than metering related costs. Where customers own their own substation and connect directly to the transmission system, the customer causes no distribution costs to the utility. These customers are typically served either through special contracts or under a transmission voltage service rate schedule. Further, not all customers use the same level of distribution facilities. For example, customers may own their own transformers. Some larger customers may be served at primary voltages only and thus use no secondary facilities. For very large customers, the customer may use only the three phase primary system operating at the upper end of voltages for the primary system. Where the utility data supports the identification of the facilities at a detailed level, it is possible to reflect the actual facilities used. Distribution costs may differ based on the facilities required to serve some customers. Some loads require extra facilities to serve a load based on unique load characteristics such as low power factor or frequency regulation for intermittent loads. In that case, the customer may require special rate provisions such as a facilities charge to pay for the extra investment. When customers share common load characteristics they may still warrant a separate class of service. This is particularly important to recognize that partial requirements customers require their own class of service because of the unique load characteristics of this type of customer.

For distribution costs found in FERC Account Nos. 364 - 374 either all or a portion of the costs are customer related because they are caused by customers. For Account No. 369 - Services, each customer has a service designed to meet that customer's own load characteristics. Services are dedicated to a customer based on their load and each customer causes the cost of its service even if the customer never consumes any energy beyond a single light bulb. If the customer is able to avoid all volumetric electric charges and pays only a nominal, non-compensatory basic service charge the result is not just and reasonable and is a case of undue discrimination unless that minimum charge covers not only the service line costs but the component of all of the other distribution costs related to providing the customer access to the electric system. More importantly, there are demand related costs associated with the distribution system that must also be recovered. Partial requirements customers who use little or no net energy must still have a distribution system designed to meet the maximum non-coincident peak of the customer. UNS Electric must have an opportunity to recover these costs as well.

Q. **How is the appropriate level of meter and metering related costs determined by customer class?**

A. Electricity will not flow into a premise (at least not legally, unless it is an un-metered lighting customer) without an electric meter (Account No. 370). Meters are virtually the same for small customers. However as the size of the customer increases, the meter installation becomes increasingly complex and the cost of meter sets increases. In addition, Account Nos. 371 – 373 (investments on the customer's premise) represent facilities that are also customer related. In the case of these facilities, the customers who request the extra service provided by these facilities typically pay for these directly as in the case of Account No. 373 related to lighting. In addition to the costs of Account Nos. 369 - 373, a customer cannot be connected to the system (or receive service) without a minimum level of distribution services provided through the assets in Account Nos. 364 - 368. These accounts support the basic distribution facilities that must be extended to connect new customers to the system and to meet the maximum demand of those customers. All existing premises were at one time new customers for whom the system must have been extended. Further, the utility must continually replace aging infrastructure to continue to serve all customers regardless of their annual kWh usage. In the case of these distribution facilities, the minimum size of equipment commonly installed under current policies and procedures represents the costs caused by customers in order to connect the minimum load to the system. The minimum system concept assures that customers who cause the costs of facilities to interconnect to the utility are properly allocated those costs. The current costs for new, minimum sized facilities are a fundamental component for estimating the marginal customer costs for UNS Electric. The demand component of these costs also needs to be recovered to compensate for standby and supplemental services and in addition to make available the starting requirements of the in-rush current that is not typically provided by a DG installation.

Q. **Are there other costs that are customer related and should be allocated to the basic service charge calculation?**

A. Yes. First, a portion of the O&M associated with the distribution plant accounts that are allocated on both customer and demand are appropriately allocated to customer related costs as well. In addition, where all of an account is allocated as customer-related, all of the O&M should also be allocated to customer costs. Second, customer service related expenses should be fully allocated to customer costs. Third, a portion of general plant costs should be allocated to customer costs to include such items as customer service facilities and other types of facilities such as the meter shop, stores and tools and equipment.

Fourth, a portion of administrative and general expenses should be included in the customer costs as well. Inclusion of general plant and administrative and general ("A&G") costs is based on the requirement that significant overhead costs are related to direct payroll costs included in the O&M accounts for distribution and customer service expenses. This is the concept of capturing the fully loaded costs of the service provided and includes not only workspace costs but pension and benefits cost and other items related directly to employee costs. These costs are also a proxy for the marginal customer cost study.

Q. **Please discuss the classification and allocation of distribution plant.**

A. As noted above, distribution plant is classified as demand, demand and customer, or just customer depending on the costs. Each component of the distribution system requires a different allocation factor based on the classification of the costs and the role that customer diversity plays in causing the costs. For plant functionalized as distribution plant and found in accounts related to facilities associated with distribution substations (Account Nos. 360-363), the plant is classified as demand and is allocated on the class contribution to the system NCP. Substations reflect the diversity of the customers served out of a particular substation. Typically, substations have different mixes of customer class and loads. As a result, substations often peak at times different from the system peak loads. Some substations may even have peak loads in a different season of the year than the system. The use of the sum of the class NCPs accounts for the differences that occur in the capacity demand on substations. Diversity of load on the distribution system is greatest at the substation level where multiple feeders serve a variety of customers and loads.

For distribution facilities in the accounts related to the power lines (Account Nos. 364-368) where power is delivered to the interconnection point with the customer, the costs are classified as both customer and demand. While there are several methods to classify these costs between customer and demand, the minimum system approach is the most consistent with cost causation because it represents the actual cost of connecting a customer to the system to serve the minimum load that meets the parameters of the approved line extension policy. Any investment, greater than the minimum system, must be related to the customers' maximum demands on that portion of the system. Thus, in addition to the customer allocation the demand allocation is based on the sum of the customers NCPs for each class of service. For the remainder of the distribution accounts (Account Nos. 369-373), the costs are classified as customer and are allocated on a customer basis with as much direct assignment of costs as possible. The final distribution account (Account No. 374) is related to amortization of polychlorinated biphenyl ("PCB") related costs and is allocated based on the transformer investment.

Q. Is there a listing of allocation factors?

A. Yes. Allocation factors are listed in Schedule G-7.

Q. During the rate design process, did you achieve parity?

A. No. The Company strives to achieve parity where possible, but due to the principle of gradualism, we made some reasonable adjustments. The impact on customers must be compared to the benefits of moving to fully cost-based rates. This approach moderates what would have been even larger variations in the percentage rate changes some classes would have received. In other words, we balanced the future need to move each class towards rates that are more reflective of cost of service while recognizing that such a move must be tempered with other factors like gradualism. Some classes will be affected more than others because their below cost of service rates have been subsidized by other customers for many years. The Company is attempting to move in the general direction of parity between classes, and send customers more accurate price signals, but to truly achieve this goal will likely take a few more rate cases.

To better understand how the return on plant varies by rate class based on the different assumptions the table below reflects the by class return on plant at the Company's proposed rates under three types of demand allocation methods. Historically, the Company has used the Peaks and Average method, but in order to address an argument that the Peaks and Average method may have the effect of doubling some portion of demand related costs that are allocated to certain rate classes, in this case the Company has chosen to move to the Average and Excess method. This is the method used by Arizona Public Service Company and is a commonly accepted methodology used throughout the utility industry.

CCOSS COMPARISON OF DEMAND ALLOCATIONS

	TOTAL	RESIDENTIAL SERVICE	SMALL GENERAL SERVICE	MEDIUM/ LARGE GENERAL SERVICE	LARGE POWER SERVICE	LIGHTING
Average&Excess & 4CP						
Demand	334,908	202,528	28,811	88,849	14,175	545
RETURN AT PRESENT RATES	2.31%	-3.88%	-1.02%	16.02%	27.95%	3.94%
RETURN AT PROPOSED RATES	$21,570,144	$9,986,026	$1,754,928	$9,196,636	$519,927	$112,627
RETURN ON RATE BASE	7.93%	6.00%	6.40%	12.96%	9.06%	7.87%
Peaks&Average & 4CP						
Demand	334,908	192,951	24,300	103,090	14,288	278
RETURN AT PROPOSED RATES	$21,570,144	$11,097,415	$2,278,387	$7,543,988	$506,806	$143,548
RETURN ON RATE BASE	7.93%	6.82%	8.90%	9.84%	8.76%	10.84%
4CP Allocation						
Demand	334,908	211,252	23,829	90,093	9,733	-
RETURN AT PROPOSED RATES	$21,570,144	$8,973,454	$2,333,054	$9,052,279	$1,035,485	$175,871
RETURN ON RATE BASE	7.93%	5.28%	9.18%	12.67%	26.26%	14.52%

B. <u>Marginal Cost of Service Study.</u>

Q. Please explain why a marginal cost study is of value in this case.

A. There are several reasons why knowing the marginal cost is valuable in designing rates. First, economics tells us that prices set on marginal cost leads to the efficient use of scarce resources. Customers cannot make efficient decisions about how to spend their energy dollars, including capital investment, unless they know how costs will change at the margin. For example, under cost based rates, if a DG customer and a full requirements customer use exactly the same average distribution system components the rates charged to both customers for those services should be the same. If the DG customer uses more of some service, such as voltage regulation, because of the intermittent nature of the solar PV for example, that extra cost should be borne by the DG customer. If rates do not recover the same or even more costs from the DG customer in this instance, rates are no longer just and reasonable and the allocation of energy dollars is economically inefficient because of the subsidy.

The second reason for understanding marginal costs is that if a customer pays less than marginal cost for the service, other customers would be better off if that customer was not served by UNS Electric. This situation is analogous to an extension policy where if the revenues are inadequate to support the investment, the customer makes a contribution to defray the excess costs so that other customers do not have their rates increased to provide a connection subsidy at the margin.

Third, marginal cost provides a guide to rate design. Essentially, the price of any unbundled service should not be less than marginal cost. In the case of the basic service charge, the charge is really more appropriate classified as an access charge. That is, it represents the cost of having access to the unbundled distribution services of the utility. Therefore, the marginal cost study identifies what the floor is for establishing a basic service charge where the embedded cost study indicates in total the revenue requirement to be recovered from the combination of all charges. This establishes a minimum basic service charge for the class.

Q. Please describe the marginal customer cost study.

A. Studies used to calculate marginal costs are common in rate case filings and use relatively consistent methodologies. Marginal cost studies focus on the change in costs associated with a small change in the number of customers added to the system or the cost to replace the current customer related infrastructure to continue service to an existing customer. Marginal costs are forward looking and require making estimates of future costs with an understanding of the elements that drive those future costs. As a practical matter, marginal costs bear no relationship to the mix of actual historical costs that constitute the utility revenue requirement. The reasons that marginal costs do not reflect actual costs used in revenue requirement calculations include the following:

- The relationship between historic and prospective costs reflects changes in technology.
- Sunk costs (the fixed cost of the existing system) do not impact marginal cost but may account for a large portion of the test year revenue requirement particularly where economies of scale are significant.
- The underlying impacts of inflation on prospective costs cause such costs to differ from past costs.
- Additions to the system are lumpy and as a result utilities optimal additions often include more capacity than the marginal change in customer count.

Q. What are the steps involved in estimating marginal cost?

A. To estimate marginal cost, the first step requires determining the change in cost associated with the addition of a new customer on average. I say on average because there are two different types of customers that may be added to the system. The first type of customer is added at a point on the existing system and thus requires a smaller investment than a customer that requires a larger investment such as a line extension. The second type of customer is added at the periphery of the system and requires extra investment to connect the customer to the distribution system. The marginal cost study takes this into account by weighting the proportion of customers that are in each category.

Electric distribution systems (from the customer's meter up to the feeder coming from the distribution substation) are typically built using engineering design standards that take into consideration the density of customers in a particular location and the expected loads of those customers. For example, an area with all-electric homes may have different design standards than an area where the homes are not electrically heated. Distribution facilities for larger commercial and industrial customers are generally designed on a case-by-case basis, given the expected peak load of the customer. In short, the local distribution system is designed based on the design load of the customers to be served ultimately, not specifically on the number of customers or their actual loads at any given moment. The concept of a network cost provides a convenient way to discuss the marginal distribution costs. Network costs represent the cost of the interconnected facilities that serve local loads and include: substations, feeders, transformers, service drops and meters. Feeders may be primary or secondary lines depending on the location of the customer and the design of the system. The customer component of these systems is related to the smallest size of the equipment that is installed to serve customers. If larger equipment, such as that required for all electric homes, is installed the extra costs are demand related. The economies of scale in the distribution system mean that the demand related cost is much less significant than the customer component.

Q. Have you provided the marginal customer cost study results?

A. Yes. The results of the study are attached as **Exhibit CAJ-1** and consist of three schedules. Schedule 1 is a summary of all of the components, the costs and provides the marginal customer cost for residential and small general service customers. Schedule 2 provides the minimum system investment for each component of the customer marginal cost along with the levelized carrying charge rate for each component to produce the revenue requirement for the component. Schedule 3 provides the customer related expenses based on the embedded cost study that are customer related.

Q. **How have you identified the minimum size components used by UNS Electric in the delivery system?**

A. Yes. We have worked with the Company's distribution engineering and operations groups for their input to determine the smallest standard size of facilities used and with the accounting function to determine the fully loaded installed costs of these components. Schedule 2 in **Exhibit CAJ-1** provides the cost of the minimum system components. In addition, the schedule provides the economic carrying charge rate and the appropriate weighting for customers requiring a line extension. This schedule produces the marginal revenue requirement for customer-related capital expenditures. The economic carrying charge rate uses the Company's capital structure and the marginal cost of the components of that structure. The forward looking nature of a marginal cost study requires that the capital cost be estimated on an incremental basis, not on embedded costs.

Q. **Have you identified the customer related expenses?**

A. Yes. The customer related expenses may be found on Schedule 3 in **Exhibit CAJ-1.** These expenses were based on embedded costs as a proxy for long-run marginal costs. In the short-run these costs would be zero because adding one customer does not change most of these costs. However, at some level these costs would increase by an amount related to the average cost when a minimum number of customers have been added. This approach provides a reasonable proxy for the O&M related costs.

Q. Please summarize the results of the customer costs on an embedded and a marginal cost basis.

A. The results are summarized in the table below.

Table 1

Cost Study	Residential	Small General Service
Marginal Customer Cost	$51.82	$102.03
Embedded Customer Cost	$14.00	$28.18

Q. Why are marginal customer costs so much higher than embedded customer costs?

A. There are several reasons marginal costs are much higher than embedded costs. First, as part of the Company's efforts to improve service reliability and have the capability to refine its rates to reflect 21st century unbundled rate design, the costs reflect a significant change in metering technology. These meters are more costly than the traditional watt hour meters used since the 19th century. Second, the impact of inflation on certain portions of the distribution assets has been significant. This means that depreciated original cost for these assets is far below the replacement cost for these assets. Third, the pattern of infrastructure replacement differs from the installation of all new infrastructures. This timing difference results from the different useful lives of the original infrastructure originally installed to serve customers. At any point, the average age of assets and the pattern of cost recovery is significantly different resulting in higher marginal costs.

Q. Please explain how the embedded and marginal cost of service studies provide the necessary support for the proposed basic service charge levels.

A. The embedded cost of service study guides the allocation of revenues among the classes of service; the study, which includes use of the minimum distribution system approach, clearly identifies the embedded levels of distribution, customer related, and other costs by class of service. In order to fully evaluate the appropriate level of basic service charge, a marginal cost of service is required in order to support and reflect a valid price signal related to connecting customers. To the extent that the basic service charge is set below the marginal cost level – existing customers will be subsidizing the costs of connecting new customers. Together, the embedded and marginal cost studies provide the Commission with the full picture as to how total revenues should be allocated across classes; and in turn, how customer costs and the cost of connecting a customer should be set to send correct price signals to customers and to encourage economic use of the system.

III. RATE DESIGN.

A. Overall Objectives of Updated Rate Design.

Q. What are the Company's objectives in rate design?

A. The Company's primary objective is to modify existing rates to recover costs in a more equitable manner from all similarly situated customers. The Company is proposing to do this by shifting more of the fixed costs into fixed rate components for the more than 95% of the customers who are on a two-part rate and to create rate classes that contain a more realistic grouping of customers.

To move toward this objective the Company must continually evaluate and adjust rates to evolve with changing cost structures, customer usage patterns, market changes and technology changes. An important first step is to move toward more equitable rate design that will recover more of the system fixed costs, in rate components that better reflect system usage.

Q. Are there other significant rate changes that need to be made to move toward more equitable structures?

A. Yes. The Company is proposing rate class changes to more appropriately group customers by the way in which these customer groups use the system. A new MGS class will be established and a maximum kW level placed within the rate schedule. This will allow the new Large General Service ("LGS") class to be modified to contain only the largest general service customers. This will also allow the LPS class to be modified to contain only customers taking service at transmission level voltage. The Company is proposing the elimination of a rate tier in the Residential rate class and the addition of a tier to comparable TOU rates to prevent higher energy usage customers from taking advantage of the TOU rate without having to modify usage habits.

Q. Are there other reasons justifying the need for UNS Electric to update and modernize its rate schedules?

A. Yes. In addition to the reasons outlined above, UNS Electric's proposed rate design has two secondary objectives: (1) to better align the Commission's policies with the Company's need for fixed cost recovery and (2) to reduce existing cross-subsidies within customer classes and between customer classes. To meet these objectives, the Company proposes: a lower percentage rate increase for classes presently paying significantly more than the system average return on rate base based on the results of the CCOSS; and a higher percentage rate increase for classes presently paying significantly less than the system average return on rate base, where the resulting bill impact is reasonable and consistent with the gradualism principle. **Exhibit CAJ-2**, which I discuss in more detail below, sets forth average annual bill impacts for each of the rate classes based on the Company's proposed rates and estimated Riders as of the rate effective date which the Company believes is more representative of the true impact experienced by the customers.

Q. What other considerations were made in developing the Company's rate design proposals?

A. As we analyzed each of the proposed rate design changes and evaluated their potential impacts on customers, we had to develop a full understanding of how these changes would affect revenues. Our considerations focused on billing determinants,[6] ratchets,[7] and consistency. To best determine the true impact on the customer and the Company revenues, we went to great lengths to determine the appropriate levels of billing determinants. It was essential that we had a complete understanding of the billing determinants as we modified provisions within the tariffs. For the Demand Charge in the new LGS class, we evaluated how the billing determinant changes will impact revenues as the ratchet for the former LPS customers taking service at distribution system voltages is changed from a 100% ratchet to a 75% ratchet as they are blended into a rate class with the largest former LGS customers. The change should not result in an inadvertent increase in rates for any of the former LPS customers. Aside from this change, the Company is proposing to maintain the design relating to the Demand Charges approved in the last rate case.

Q. What must be considered with respect to whether the ratchet and billing determinants result in just and reasonable rates?

A. First, in developing these proposed modifications, a thorough analysis must be performed to best ensure that the impacts on the customer are understood and the proposals are fair and equitable. Second, in the event even one of the design parameters is changed during

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[6] Billing determinants are number of units on which each of the billing components would apply to generate the Company's Revenue Requirement. By class, this would include the number of customers on which the basic service charge applies, the number of total Demand units on which the Demand Charges apply and the number of kWh on which the volumetric charges apply.

[7] A ratchet is a billing provision under which the Demand Charge for each month is based on the highest measured or billed demand over a period of time in the previous year. This mechanism minimizes risk of not recovering fixed costs and properly compensates for the year-round expenses incurred to provide service to a customer.

the rate case process, the billing determinants and ratchets must be re-evaluated to assure bill impact is acceptable and revenues generated are as expected.

If any change is made to a rate design component, an equivalent review and modification of an appropriate change in billing determinants must be made to the revenue proof to assure the revenue proof reflects the appropriate recovery of revenues.

B. Specific Rate Design Changes.

Q. Please provide an overview of the changes that the Company is proposing that are not class specific before moving to the individual rate classes.

A. First, the Company is proposing to increase all monthly basic service charges in a manner consistent with the results of the CCOSS and equitable fixed cost recovery. UNS Electric proposes an increase in monthly basic service charges to levels that better match, but are not equivalent to, the customer-related costs and the minimum cost to serve the customer, as indicated by the CCOSS and the marginal cost study used as a guide to determine what the minimum cost to serve a customer should be. The Company's requirement to ensure that service is available (including having the distribution infrastructure in place) does not change if a customer decides not to use energy on a given day. This is why the majority of UNS Electric's costs are fixed in nature.

Second, the Company is proposing to change the PPFAC charge to a percentage based rate instead of a per kWh rate. This will be discussed more thoroughly later in my testimony.

Third, for TOU customers, the Company is proposing to add a tier to the rates where the non-TOU option contains a tier. In the last rate case, the Company proposed to eliminate the tiers for TOU customers in the hope that the simplified rate would be more appealing to the customers. This inadvertently established a perverse situation where the largest usage customers could benefit from lower average rates and, as a result a lower bill without changing their consumption to off-peak from on-peak times. This unintended consequence can be rectified by adding a tier back to the appropriate TOU rates.

Fourth, for most non-interruptible classes with a Demand Charge, the Company proposes to establish minimum and/or maximum demand amounts (billing demand levels) in order for a customer to become and remain eligible in the individual classes. This should provide for better parity within the classes and thus less intra-class inequity and make it easier for customers to stay on a particular rate schedule and eliminate the confusion and added cost associated with tracking and regularly changing a customer from one class to another.

Fifth, the Company's current LGS and LPS rates will be redesigned. The Company is not proposing to change the ratchet mechanism in the rates, but it is proposing to create a new MGS rate that will contain all but a few of the former LGS customers, but will be limited to only those customers with a measured demand of less than 750 kW in any month. Other than the cap, the design of the new MGS rate will be the same as the current and new LGS rate (e.g. 75% ratchet). The new LGS rate will not undergo a rate design change (e.g. the 75% ratchet will remain), however the rates will be recalculated to blend about 10 of the largest former LGS customers and about 7 of the former LPS customers (those taking LPS service at less than 69 kV – distribution level voltage). The LPS class will not undergo a rate design change, but will only be available to customers taking service at greater than or equal to 69 kV – transmission level voltage.

For these firm classes the billed demand amount will continue to be based on the greater of: (i) the greatest billed (measured for LPS) fifteen-minute interval demand read of the meter during all hours of the billing period; (ii) 75% of the greatest billed fifteen-minute interval demand read of the meter during the prior 11 months (100% of measured for the LPS class); or (iii) the contract capacity or the specified minimum demand amount whichever is greater.

Q. Does the existing rate design, which recovers a significant portion of the fixed costs through volumetric energy charges for most rate classes, create problems other than revenue instability?

A. Yes. First, the collection of significant fixed costs through energy charges places a disproportionate burden on the larger energy users within a rate class that, on average, pay more than their share of fixed costs. Even though a higher load factor customer is using the system more efficiently (and therefore more cost effectively) than a low load factor customer, having a larger proportion of the fixed costs in the energy rate will result in that higher load factor customer paying a disproportionate amount of the system cost. Shifting revenue collection away from energy charges reduces the cross-subsidization that occurs when usage within customer classes varies significantly.

Second, an over-dependence on fixed cost recovery through volumetric energy charges creates an economic disincentive for the utility to promote conservation, EE, and DG. If non-fuel rates are collected primarily through volumetric charges and the recovery of costs is dependent on usage, the associated reduction in sales significantly erodes a utility's ability to earn its Commission-authorized rate of return. This is true even with the LFCR mechanism, as currently designed, since 50% of any demand charge reductions and the entire generation component of retail rates is not currently included in the LFCR.

Q. Can this disparity be resolved solely through modification of the monthly basic service charges?

A. Only partially. The basic customer-related charges are a good starting point to identify what should be included in the monthly basic service charge for each class, but they do not tell the whole story. Historically, basic charges are limited to metering, meter-reading, service (service drop) to the specific customer, and customer service and billing. While these costs should be included in the basic service charge and may be used as the guide to what the basic service charge should be for classes with Demand Charges, they are not sufficient for classes without a Demand Charge.

Q. Why is it necessary for demand-related costs to be included in monthly basic service charges for classes with rates that do not include a Demand Charge?

A. As discussed earlier in my testimony, the minimum cost of serving a customer includes more than what has historically been seen as customer related charges. Without some level of demand-related cost being included in the basic service charge for classes without a Demand Charge, a disproportionate amount of the Company's fixed costs must be recovered in volumetric energy charges. Consequently, if customer energy usage falls, the Company will not have a reasonable opportunity to earn its Commission-authorized rate of return. Also, since the current LFCR rate excludes the generation component of retail rates, this will only be exacerbated as the amount of sales erosion from increased levels of EE and DG continues. Modifying the rates to include a higher proportion of fixed costs in the monthly basic service charges will send customers the right price signals and provide additional support for the Company's efforts to promote EE and DG. Specifically, because the residential and small general service classes currently do not have a demand charge, the cost of at least some of the fixed cost items required to serve a customer (such as transformers and distribution conductors) should be included in the monthly basic service charge. It was even acknowledged in the

Commission's decoupling workshops that increased fixed charges would help minimize the revenues lost and ultimately recoverable in any decoupling adjustment (including a partial decoupler like the Company's LFCR mechanism.)

Q. Why does UNS Electric prefer increasing the monthly basic service charges over further increasing the energy (per kWh) charges to recover fixed costs?

A. For the smaller rate classes, UNS Electric currently collects the majority of its fixed costs through a volumetric energy charge, which is a conceptually flawed rate design. This is because the bulk of a utility's costs are fixed and do not vary with the quantity of energy the customer uses on a given day. The Company is in the business of providing safe and reliable energy service. This means that facilities and personnel must be in place to ensure that customer demand is met – 365 days a year, no matter where or when the service is requested in the Company's service territory. In short, the Company earns a regulated rate of return on the infrastructure necessary to provide electrical service – on demand - to its customers. The obligation to provide safe, adequate, and reliable service does not change, regardless of whether or how much energy UNS Electric's customers consume. This is why the majority of UNS Electric's costs are fixed.

Periodic variation in energy consumption has limited impact on the true, non-fuel cost of serving customers. Most non-fuel costs are fixed and will ultimately produce a mismatch between costs and revenues when a substantial portion of the revenues are recovered through weather-sensitive sales. Increasing basic service charges helps to address this disparity. When basic service charges are increased, energy charges are decreased (holding revenue requirement and other factors constant). Fixed basic service charge revenue stays relatively constant within a given month – despite weather variations, conservation efforts or (in the short run) economic activity. Consequently, basic service charges provide a relatively stable and predictable source for funding fixed costs, which constitute the bulk of a utility's marginal costs.

Q. Will the Company's proposed rate designs guarantee it the ability to earn its authorized rate-of-return?

A. Absolutely not. The Company's rate design hardly guarantees achieving its Commission-authorized rate-of-return ("ROR"). For the majority of UNS Electric's customers, a significant percentage of *margin* (non-fuel revenue) recovery will still be collected through the energy charges (volumetric or per kWh). For example, UNS Electric's residential rate RES-01 (which is the rate responsible for approximately 42% of the system margin revenue) collects nearly 73% of classes' margin currently through energy charges. This is similar to the small general service class as well, and the small general service class accounts for another 8% of the Company's marginal revenues. This large allocation of fixed cost to an energy charge potentially causes large swings in the amount of revenue collected to provide the Company an opportunity to earn its authorized ROR. Warmer than normal summer weather could result in over-recovery and cool summer weather will result in under-recovery of margin revenues. Of course, any conservation effort or decreased use per customer will, by design, result in under earnings for the utility. Further, even with a three-year rate-case cycle, factors such as operating costs, material costs, and plant expansions have consistently increased. These factors work against the Company's ability to earn its authorized ROR.

1. **Residential Rates.**

a. **Monthly Charge.**

Q. How do UNS Electric's current residential monthly basic service charges compare to other Arizona electric utilities?

A. The Company's residential basic service charge covers a smaller portion of fixed costs than the residential basic service charges of other electric utilities in Arizona. UNS Electric's residential basic service charge is only $10.00 per month ($4.90 if currently on a CARES rate). In contrast, APS, Trico Electric Cooperative, Inc. and Salt River Project ("SRP") have basic service charges ranging $15.00 to $20.00 per month, with TOU basic service charges $18.00 to $36.00 per month range. APS also has a Demand Charge that applies in addition to the basic service charge in one of its residential rates. Considering that all electric utilities incur substantial fixed costs to serve residential customers, and that those fixed costs typically exceed the higher basic service charges approved, for those utilities, UNS Electric's current monthly service charge should be increased. While it is imperative to start addressing the issue of moving basic service charges towards reflecting actual fixed costs incurred, the Company realizes the difference cannot be fully addressed in a single rate case. Therefore, UNS Electric is proposing an increase in the monthly customer service charge that makes a step in the right direction, but does not necessarily fully address the issue.

Q. With that background in mind, what increase is UNS Electric proposing to the residential monthly basic service charge?

A. In an effort to move towards more appropriate monthly basic service charges for the residential rate class, UNS Electric proposes to increase residential basic service charges from the current $10.00 per month to $20.00 per month for both the standard and TOU residential customers when new rates are implemented. The proposed basic service charge is still only approximately 37% of the $54.46 in combined customer (*e.g.* meter reading, billing, etc.) and demand related charges identified by the CCOSS for the residential customer and the charge is still below monthly basic service charges that this Commission has previously approved for other electric utilities.

Q. Will the gradual increases in the monthly basic service charges also smooth out the amount of revenues that will be recovered through the Company's proposed LFCR mechanism?

A. Yes. Besides reflecting sound rate design principles, increasing these basic service charges will also help to mitigate the amount of lost revenues to be recovered in the LFCR. This is because as the fixed charges are increased, the volumetric charges are proportionally decreased for each rate class. Further, because the energy rate is lower, the total lost margin will be smaller for each kWh lost as the result of Commission approved EE and DG programs.

b. <u>Volumetric Rate.</u>

Q. What volumetric rate is UNS Electric proposing for the residential rate classes?

A. Schedule H-3 shows the various rates and rate components for each of the Company's proposed rates. For the Residential RES-01 rate class, UNS Electric proposes an average overall volumetric rate of $0.0668 per kWh (exclusive of purchased power and fuel costs), resulting in a $0.0247 per kWh increase on the average volumetric rate for the RES-01 rate. This rate is identified as the "Delivery Services-Energy" charge on the tariffs and is designed to recover the portion of fixed costs not covered by the monthly basic service charge.

Q. Describe the change for Rate RES-01.

A. For Rate RES-01, which is the residential rate for nearly 80% of our customers, the Company is proposing only one substantial rate design change other than the increase to the basic service charge. The Company is proposing to eliminate the third tier in the residential rate class. It adds no cost-based value to the rate class other than exacerbating the issues of fixed cost being inequitably recovered from the higher usage customers. The Company would like to maintain only two tiered rates for the residential classes. Additionally, a trend toward a declining use per customer and any conservation related loss of sales would generally reduce consumption in the highest rate tier and exacerbate the impact of EE and DG losses as it relates to the Company being able to earn its authorized rate of return.

Q. Describe the changes to the two RES-01 TOU rates.

A. Except for the change in the basic service charge described above, the only substantial change that the Company is proposing to make to the residential TOU rate is to add a second tier similar to what is currently in place for the Residential Super Peak TOU rate and as described earlier in my testimony and the Company's proposal for the RES-01 rates.

2. <u>Non-residential Rates.</u>

Q. Describe the changes the Company is proposing for the general service customers and the large power service customers.

A. Much like what the Company is proposing for the residential customers, the changes for general service and large power service customers also are designed to more appropriately recover fixed costs in the fixed portion of rates. Basic service charges for the non-residential classes also need to be increased to amounts closer to levels indicated by the CCOSS. The only other changes have been described earlier in my testimony and include the establishment of a maximum demand for eligibility in the new MGS rate and a higher minimum billing demand for the new LGS rate, with the qualifications for the LPS rate being changed to only include customers taking service at greater than or equal to 69 kV. The Small General Service rate ("SGS") will maintain the current third tier and no demand charge in the standard rate offering.

a. <u>Monthly Charges – Basic Service Charge and Demand Charges.</u>

Q. What monthly charge is UNS Electric proposing for non-residential customer classes?

A. For SGS customers, UNS Electric is proposing an increase to the basic service charges for the same reasons as discussed for the residential class-, since no Demand Charge is in place for this class of customers. The proposed basic service charge will reflect an increase from the current $14.50 and $16.50 per month to the proposed $30.00 per month for both standard and TOU rate classes. The SGS class will continue to have a provision that a customer will be moved to the new MGS rate in the subsequent month if the customer's consumption meets or exceeds 12,000 kWh in consecutive months.

For the MGS class, the basic service charge will reflect an increase from the current basic service charge in place for the former LGS class of $50 and $52 per month, to the proposed $100 per month. As set forth in Schedule G-6-1, line 32, the proposed MGS charges are still below the true costs of providing service. Additionally, the MGS class will maintain the current minimum billing demand as the former LGS class applied to all customers within the class. The minimum demand will be 20 kW. A new cap of 750 kW will be established such that any customer exceeding the cap for a billing month will automatically be moved, in the subsequent month, to the new LGS rate class. The customer must remain there for at least 12 months without exceeding the 750 kW demand to qualify to move back to MGS.

For the LGS class, since this is only for the largest former LGS customers and select LPS customers, all exceeding 750 kW of measured demand, the basic service charge will be established at $300 per month. The TOU classes will be the same. As set forth in Schedule G-6-1, line 32, the proposed general service charges are close to the true costs of providing service. Additionally, the LGS class will have a minimum billing demand applied to all customers within the class. The minimum billing demand will be 450 kW, and there will be no cap on demand for eligibility in the LGS class.

The current LPS class has two types of customers. Service is taken at either less than 69 kV or greater than or equal to 69 kV, with the basic service charge currently established at $1,200 per month for either level of service. As mentioned earlier, the < 69 kV customers will now be in the new LGS rate class and will be served at a lower basic service charge in order to help move this class closer to the CCOSS based rates. Based on the results of the CCOSS the customers taking service at greater than or equal to 69 kV are also contributing at a level above the levelized return on plant, so the Company is not proposing to increase their basic service charge from the current $1,200 per month. For the redesigned LPS class, the current minimum billing demand will be applied to all customers within the class. The class currently has a 500 kW minimum billing demand which will be maintained.

Based on the results of the CCOSS, the Company believes these new basic service charges are just and reasonable as they will help levelize the class's contribution to the cost of service while still allowing the Company to recover more of its fixed costs through a fixed charge.

b. <u>Calculation of Demand Charges.</u>

Q. How is the Company proposing to calculate demand charges?

A. As discussed above, UNS Electric is proposing to maintain the way it calculates the Demand Charges in those firm rate tariffs where a Demand Charge is part of the rate design. This would include the existing Rate LGS, LGS-TOU, LGS-TOU-S, LPS, and LPS-TOU rate tariffs, as well as the new MGS rate classes.

Consistent with the criteria in the current tariffs, the LGS, LGS-TOU and LGS-TOU-S monthly billing demand shall be the greater of the following:

(i) the greatest measured fifteen-minute interval demand read of the meter during all hours of the billing period;

(ii) 75% of the greatest demand used for billing purposes in the preceding 11 months; or

(iii) the contract capacity or 450 kW, whichever is greater.

The LPS monthly billing demand shall be the greater of the following:

(i) the greatest measured fifteen-minute interval demand read of the meter during all hours of the billing period;

(ii) the greatest demand metered in the preceding 11 months; or

(iii) the contract capacity or 500 kW, whichever is greater.

The LPS-TOU monthly billing demand shall be the greater of the following:

(i) the greatest measured fifteen-minute interval demand read of the meter during the on-peak hours of the billing period;

(ii) one-half of the greatest measured fifteen-minute interval read of the meter during the off-peak hours of the billing period;

(iii) the greater of (i) or (ii) above during the preceding 11 months; or

(iv) the contract capacity or 500 kW, whichever is greater.

The Company is proposing to apply one general method to the MGS and LGS classes that is the same as the method used for the current LGS classes. In applying sound cost of service principles, the Company wishes to maintain the billing demand based on the "ratchet" being set at the levels defined above and in the tariffs.

Consistent with the current tariffs, the LPS class will maintain similar provisions except the prior 11 months will have a 100% ratchet applied to measured demand. For the LPS-TOU a fourth option would be used in the determination of the billing demand. This additional option would be based on one-half the greatest measured 15 minute interval read of the demand meter during the off-peak hours. This fourth option is compared to the on-peak demands in the prior 11 months in this LGS-TOU rate and the other two demand billing tests to determine the level of demand the customer is billed each month. These provisions add consistency between the classes and allow the LPS-TOU customer the opportunity to save costs in recognition of moving load to off-peak periods.

In all of the larger non-interruptible rate classes with a demand charge, the current CCOSS results indicate they are paying more than the levelized system return on plant as can be seen in Schedule G-2 – Summary at Proposed Rates, line 37. Therefore, the Company is proposing to either maintain demand charges at the current levels or decrease them where possible. Please refer to the proposed demand charges for each class in Schedule H-3.

This design continues to allow higher load factor customers to benefit from their current usage patterns, which reflect a more efficient utilization of the system and is consistent with sound rate making principles.

c. <u>Volumetric Rates.</u>

Q. What is the Company proposing for the non-residential volumetric rates?

A. Any remaining authorized revenue requirement allocated to these classes will be recovered through an adjustment to the per-kWh delivery rate for the specific class. The volumetric rates vary by class and can be found in Schedule H-3.

Q. Currently, the tariffs that apply to some of UNS Electric's large customers include a charge if they fall below a certain power factor. Is the Company proposing to change this tariff provision?

A. No. The Company is not proposing to change the way the power factor is applied and billed in the two large power service tariffs (Rate LPS and LPS-TOU). The Company is not proposing to change the current tariffs' power factor related charges which are based on a 95% power factor. UNS Electric will continue to apply the provision in its Rules and Regulations that allows the Company to require installation of power factor correcting equipment on a regular basis, if the provision in the tariffs does not encourage the customers to operate at improved power factors.

The Company is proposing to add language to the new LGS tariffs that will allow the Company to require a customer to install equipment that will allow for calculating Power Factor and billing it in the same manner as specified in the LPS tariff if the Company believes the customer's usage habits are having a detrimental impact on the system.

3. TOU Rates.

Q. What changes is the Company proposing to its TOU rates?

A. As discussed above, the Company is proposing to add a tier to all TOU rates at the same consumption level as the comparable standard delivery rate tier. In the interest of simplifying the TOU rates in the Company's last rate case, all the tiers were eliminated in the residential TOU rates and only a single on-peak and single off-peak rate are included in the tariff. After reviewing customers' usage and the associated bills, it was determined that the tier rate structure must be maintained between the standard and TOU rate or an inadvertent incentive is created for the largest customers to shift to TOU without changing consumption patterns. Obviously, the current tariff structure does not encourage customers to move consumption from the on-peak hours to the off-peak hours and must be modified. Adding the tiered rate back to the RES-01 TOU rate will result in price signals that are more consistent with the standard rate with an incentive to move their consumption from on-peak hours to off-peak hours in order to generate savings on their bill. The Company is also proposing to retain the current Residential Super Peak TOU rate with only conforming changes and updating the rates and basic service charge.

Additionally, with the proposed increase in the Basic Service Charge to a more appropriate level for all classes, the Company is proposing to eliminate the additional $2 per month historically added to the TOU customer's Basic Service Charge. No other structural changes will be made to the TOU rates.

The Company is proposing to retain the School TOU rates for the MGS and LGS classes, but eliminate the smaller SGS-TOU School rate. The SGS-TOU School rate classification is designed for a smaller customer, and as a result, no customers have requested service under that tariff. The SGS-TOU-S rate will be replaced by the new

MGS-TOU-S rate which will allow more schools to take advantage of the tariff. The rates are similar to the equivalent standard service rate with TOU based peak and off-peak fuel costs.

4. Lighting Rates.

Q. What changes are being proposed to UNS Electric's Lighting Rates?

A. The Company is proposing to continue updating the lighting rates. Lighting services are designed to be offered to private or public outside lighting conditions where no meter is installed. The prices vary by the wattage and type of light bulb. The service includes the recovery of the initial cost of the pole, wiring, and fixture, as well as a normalized cost to maintain the light itself. The maintenance costs have continued to increase, however the rates have not kept up.

The lighting rates were substantially below the cost of service based levels in UNS Electric's last rate case and required an increase to bring them up to the appropriate levels. The Company's current review indicates that the Lighting rates are being heavily subsidized and increases are warranted. The proposed rate increase, although higher on a percentage basis than most other classes, will not recover the costs incurred to serve the lighting customers.

5. Partial Requirement and Qualified Facility Rates.

Q. What changes is the Company proposing to make to the tariffs defining service to customers with Qualifying Facilities ("QF")?

A. The Company is proposing to maintain the current QF-A, QF-B and QF-C tariffs which define how service will be offered to customers installing Qualifying Facilities. For these customers the only substantive change would be that, in our proposal, the standby demand would be based on the greater of the contract demand, the current month's measured peak demand or the greatest measured peak demand amount in the prior 23 months instead of the Standard Tariff's provisions. This change is necessary since a partial requirements customer can demand service from the Company at any time capacity is available. Equipment and capacity must be able to meet their full load at that time and will need to be available going forward. Therefore, it is appropriate for the customer to pay the demand charge for the greater of the current month or the preceding 23 months in order to compensate the system for the capacity used by the customer. All other rates will be consistent with those being proposed in the equivalent retail rate that the customer would have otherwise been served with the exception that any residential and small general service customer choosing this option must be on the newly proposed three-part rate for their rate class.

Q. Does the Company have pending Partial Requirements Service ("PRS") tariffs on file for consideration by the Commission and Commission Staff remaining from its most recent rate case?

A. Yes. The Company is proposing to withdraw those pending tariffs and submit the tariffs being submitted in this proceeding as its Partial Requirement Service tariffs.

Q. Besides the QF tariffs mentioned above, is the Company proposing additional Partial Requirement Service tariffs?

A. Yes. These tariffs and a related rider have been included in my **Exhibit CAJ-3,** Proposed Tariffs, and are explained in detail in the Company's witness Dallas J. Dukes' Direct Testimony.

6. Community Solar Rate.

Q. Will the Community Solar rate be changed?

A. Yes. The existing rate will be locked in place for the remainder of the customer's 20-year agreement. A new rate based on the revised fuel cost will be calculated and have the same, Commission approved, $0.02 per kWh premium added to it and placed on the Community Solar tariff for use by any customer signing up after the effective date of the new rates. This is the same process approved in the Company's last rate case.

The currently effective frozen Community Solar rates have their own 20-year term and are based on fuel costs established in prior rate cases. The rates being proposed in this rate case include reduced fuel costs in part resulting from the recent purchase of the Gila Generating facility discussed elsewhere in the Company's testimony. Since the existing tariff provisions do not prevent the customers from terminating their current Community Solar agreement, the Company believes customers may choose to terminate service under their existing Community Solar agreements and re-apply for service under the new rate if there is enough capacity for them to participate. The Company believes it would be appropriate to send a communication to existing Community Solar participants in order to be proactive and allow them to place their name in the queue for the new rate. Since the available capacity is limited, all of the existing customers may not be able to migrate to the new rate and should not cancel the old agreement until it is confirmed that capacity is available for their requested blocks.

7. <u>Interruptible Rates.</u>

Q. Will the current interruptible rate still be available to new customers?

A. No. The Company is proposing to freeze the current Interruptible Power Service ("IPS") rate. The provisions of the tariff will be unchanged for the customers currently being served on the rate and the rates will be increased. The increase proposed for this class is more than most customers since the CCOSS study shows them to be highly subsidized and since they have not historically been interrupted, the Company is proposing to increase these customer's rates more than most other rate classes.

Q. Will the frozen IPS rate still have a demand charge?

A. Yes. It will continue to have a demand charge. The charge will be increased substantially since this class has been subsidized historically. The demand charge will remain lower than the demand charge proposed for the equivalent firm service class. For billing purposes the demand charge will be calculated in the same way as the MGS and LGS classes, but consistent with the current tariff provisions, there will not be a ratchet applied.

Q. Please describe the changes the Company is proposing for the new Interruptible Rate class?

A. The current IPS rate currently has a demand charge that is approximately 61% lower (($12.81-$5.00 = $7.81)/$12.81=61%) than the LGS rates currently in effect. This results in a substantial subsidy for the IPS customer class with very little value to the Company or the other customers. They have not been interrupted in recent years and therefore provide no quantifiable benefit to the system. The company did add a provision in the last case that required a specific type of equipment be installed that would allow the Company to interrupt remotely. This provision will allow the Company to actually interrupt the customers on this subsidized rate, but would not provide a level of value to the remaining customers in proportion to the existing subsidy. As a result, many of the former IPS customers have moved to firm service. The number of customers in this class has dropped from 39 to 29 since the test year used on the last rate case. The Company would like to freeze the existing IPS tariff and prevent any additional customers from being added.

In its place the Company would like to propose an interruptible rider similar to the rider that was recently approved for TEP. This not only allows a rate that is more cost based, but can be offered in a manner more consistent with TEP and allow for a more consistent application of the rate. This rider provides for a customer to pay standard tariff rates, but allows the customer to designate a portion of their load as interruptible and receive a credit on their bill for the amount of capacity they offered as interruptible. This results in a more cost based credit for the real value of interruptible capacity in the year it is offered and protects the remaining customers. The draft rider can be seen in the attached **Exhibit CAJ-3** (Sheet No. 712).

Q. **In its last rate case, did the Company commit to create an interruptible offering that would encourage certain customers to reduce their purchases from the Company?**

A. Yes. We are proposing an interruptible rider as an option that the Company believes protects the interest of other customers and still provides the interested customer with an option that is consistent with what was discussed in the settlement process. The proposed tariff is modeled after the tariff recently approved for TEP.

8. **Economic Development Rate.**

Q. Is the Company proposing an Economic Development Rate ("EDR")?

A. Yes. UNS Electric witness Dallas J. Dukes describes the EDR rider in detail. I have included the proposed rider in **Exhibit CAJ-3** (Sheet No. 713).

9. **CARES Rates.**

Q. What is the Company proposing with respect to its CARES rates?

A. The Company's low income rates are referred to as CARES rates. The Company proposes to simplify the CARES rate by offering a single uniform discount off of the RES-01 rate. The modifications would reduce the two existing tariffs (which contains six multi-leveled percentage discount variations and two fixed discount variations) down to a single provision within the RES-01 tariff with a flat $10.00 per month discount (limited to a reduction of the bill down to zero dollars.) UNS Electric also proposes to eliminate the exclusion of CARES customers from the DSM surcharge.

Q. Please describe the current CARES rate structures.

A. The current CARES tariffs establish two types service with only one being available to current customers. Both receive a reduction to the Basic Service Charge, when compared to standard residential customers. The current CARES monthly Basic Service Charge is discounted from $10.00 to $4.90. The customer receives an additional discount on the Basic Service Charge, energy and fuel charges (depending on a customer's usage). The standard CARES customer discount drops from 30% to 10% as usage approaches 1,000 kWh. For the frozen CARES-medical customers the discount drops from 30% to 10% as usage approaches 2,000 kWh. This discount is applied to per kWh rates that are already up to 3.7% below the standard residential rate. When the customer's consumption exceeds the 2,000 kWh or 1,000 kWh cap, they receive a flat $8.00 discount to their already discounted bill.

The combination of these rate discounts totaled $581,326 during the test year for more than 6,236 CARES customers as of the end of the test year.

Q. Please describe the new CARES rates that UNS Electric is proposing?

A. Any new customer qualifying for the CARES program (or existing CARES customer moving to a new location) will become standard RES-01 customers and pay standard RES-01 rates with a flat $10.00 per month discount applied to the bill (with the discount limited to no more than the actual bill in order to prevent a bill from being below zero).

Q. What will happen to customers who are currently on a CARES rate?

A. The Company is proposing to freeze the currently available CARES rates in the same manner that it previously froze the CARES-Medical rates. The customers currently on the existing CARES rates will remain on those tariffs. Customers on the new frozen CARES rates will experience a rate increase, but the increase will be less than the standard RES-01 customer.

Q. Is the Company proposing to change whether CARES customers are exempt from the DSM surcharge?

A. Yes, consistent with what the Commission approved for TEP, CARES customers will no longer be exempt from the DSM surcharge. This will reduce the costs of testing and tracking this exemption.

10. **Buy-Through Rider.**

Q. Why is the Company presenting a buy-through tariff?

A. As part of the settlement agreement in the acquisition of UNS Energy by Fortis. UNS Energy agreed that UNS Electric and TEP would submit a buy-through tariff in their next rate case applications.

Q. Is the Company seeking approval of a buy-through rider in this proceeding?

A. No. The Company does not support it, and in fact, is opposed to the implementation of this tariff. It allows for certain large customers to "cherry pick" currently available capacity resulting from current economic conditions and will ultimately result in costs being passed on to the remaining customers. The Company is merely presenting the buy-through rider (Experimental Rider 14, Alternative Generation Service) in order to comply with the requirements of the settlement agreement related to the Fortis acquisition.

Q. Please describe Experimental Rider 14, Alternative Generation Service the Company is presenting?

A. Experimental Rider 14, Alternative Generation Service, if approved would be an optional, experimental program designed to provide an alternative generation arrangement for participating Large Power Service (LPS) customers. It would be available for a maximum of 10 MW of peak load and would be available for no more than four years from the effective date of new rates in this docket.

Under the program, the customer would select a wholesale generation service provider to sell power to the Company on the customer's behalf. The power must be delivered to one or more of the Company's points of delivery for wholesale power, as designated in a power supply agreement. The Company would take title to the power and provide it to the customer, who in turn would pay for the power pursuant to the terms and conditions in the power supply agreement, the terms of Experimental Rider 14, and other program provisions. UNS Electric would continue to supply transmission, delivery and revenue cycle services to the customer under the provisions of the customer's current retail rate schedule. The customer would also be subject to all of the charges and adjustments in the retail rate schedule, except for Power Supply Charges and the PPFAC.

The Company would purchase and manage this generation on behalf of the customer for a management fee of $0.0060 per kWh. The Company would also provide scheduling and energy imbalance service. Furthermore, the billed amounts under the retail rate and applicable adjustments would be based on the total billed kWh, kW, or billed dollar amount, including the cost of the alternative generation.

Q. Who can participate?

A. The program would be available to customers in the LPS and LPS-TOU rate classes with peak demands of 2,500 kW or more. As stated above, the program is limited to a total of 10 MW of peak load.

Q. How would customers be selected?

A. The Company would establish an initial enrollment period during which eligible customers could apply for the program. If the total MW of peak load from the applications exceeded the program maximum, customers would be selected for enrollment through a lottery process to be developed by UNS Electric.

Q. What happens if the alternative Generation Service Provider defaults or the customer wants to return to standard UNS Electric generation service?

A. The customer will be required to contract for service under this schedule for at least one year, but no longer than the termination date of the offering, if approved. If the alternative Generation Service Provider defaults, the customer would have 60 days to find an alternate supplier or be considered a "returning customer". Default provisions would be specified in the power supply agreement.

If the customer desired to return to the standard UNS Electric generation service before the contract term, due to a default or other reason, they would be allowed to do so without charge if (i) they provide one year notice (or longer) to the Company; (ii) if the rider is discontinued at the end of the four-year experimental period; or (iii) the Commission terminates the program prior to the end of the four-year experimental period. Absent one of these three conditions, the Company would provide the customer with generation service at market rates specified in the rider until the Company was reasonably able to integrate the customer back into their generation planning and provide power at the applicable retail rate schedule.

Q. What other charges would the customer be responsible for?

A. In order to help mitigate some of the cost shift to the other customers, the customer would be required to pay 100% of the first year's generation related charges in the base retail rate and 25% of the generation related charges in the base retail rates as a Reserve Capacity charge in each subsequent year the customer participated in the described program.

Q. How would the Company recover the other 75% of the generation related charges in the customer's base retail rates while the customer enjoyed the special program that allowed them to avoid the cost during the years subsequent to year 1?

A. The Company would propose that any lost revenues resulting from this type of service should be recovered through the LFCR mechanism and paid for by the other customers. If this tariff is ultimately placed into effect a modification to the LFCR POA would need to be made to accommodate the recovery of these lost revenues.

C. Bill Impacts.

Q. What is the bill impact of UNS Electric's rate design proposals?

A. The impact of any rate case on the Company's customers is always a significant concern. A great deal of time and effort was put into creating a set of rates that would keep the impact on the customers within a reasonable range and generally consistent with other similarly situated customers. These impacts have been summarized in **Exhibit CAJ-2.**

Additional bill impact data has been provided in Schedule H. The data in this schedule must be reviewed in context. For sufficiency purposes, the Company is required to submit the information in comparison to test year rates. However, this comparison will be misleading given the rate design changes and the updated fuel costs and a credit resulting from the interim benefits generated by the Gila River Generating Station. That is why I prepared the comparison of current rates to proposed rates in **Exhibit CAJ-2** that is based on consistent fuel costs, estimated deferred savings, LFCR changes, TCA changes and old versus new rates for both bill calculations.

While Schedule H-4 reflects varying levels of energy consumption, I have created **Exhibit CAJ-2** to reflect an "all in" bill impact comparison by class by using "typical" usage amounts for each rate class as of an assumed rate effective date of the Company's proposal. With respect to the residential classes, the comparisons reflect a customer that uses 983 kWh per month in the summer months and 669 kWh per month in the winter months. In year 1, residential customers under our basic residential rate (RES-01) will see just over a 2.26% increase which equates to just over $1.99 per month on average if the Company's full revenue requirement is approved. This impact includes the Company's proposed fuel cost reduction in the before and after comparison so the impact is not exaggerated by the Company's proposed change in fuel cost which reflects forecasted fuel costs. The CARES customers' existing rates are lower; therefore, even though the percentage impact appears nearly as high as the standard retail RES-01 customer, the actual dollar change to the total bill, for the same 826 kwh monthly usage, is nearly one-half of the dollar increase proposed for the RES-01 customer. The Residential TOU customers will experience even larger increases, but that is the result of bringing the TOU rate to the same level as the standard residential rate. Ideally, the customer should be required to adjust their usage habits to experience a savings on a TOU rate. That has not been the case under the current rates; therefore the Company has proposed to adjust the TOU rates to address the problem. The TOU customer that doesn't change their usage habits will pay approximately the same as a standard customer, but can experience a savings by shifting consumption to an off-peak period.

The impacts for the Residential and SGS classes are more than what is being proposed for the larger classes in order to move toward a more equitable contribution to the overall return on plant identified in the CCOSS.

The overall increase the SGS customers will see is an approximate 3.99% increase for the typical customer. In comparison to the former LGS rates, the MGS customers will see an approximate 9.67% decrease for the typical customer. The impact to the LGS customers will vary somewhat due to blending of a few former LGS customers and a few LPS customers. In general, the LGS customers who were in the former LGS rate class will see an approximate 13.09% decrease while those in the former LPS rate class will see an approximate 15.45% decrease. The LPS customers will see an approximate decrease between 7.79% and 9.67%.

Schedule H increases will reflect higher overall percentage increases due to the timing of the rate changes in conjunction with other related rider changes such as the TCA and PPFAC which will mitigate a portion of the overall rate increase requested by the Company. All rates also reflect a realignment of non-fuel components to reflect results consistent with the CCOSS and an adjustment to fuel components where possible to move all customers closer to the average cost of fuel where appropriate. All of these changes are being proposed to reflect the recovery of costs more equitably between customers within a rate class and between rate classes.

Q. Are there other timing related changes that your Exhibit CAJ-2 reflects more accurately than the Schedule H presentation?

A. Yes. While required as part of the overall filing requirements, Schedule H simply looks at the rates at the end of the Test Year and incorporates the proposed rates and determines the bill impact of the various sizes of customers in each rate class. In reality, many things will be occurring during the time rates will be placed into effect. Fuel costs will be changing and TCA rates will need to change to reflect the inclusion of transmission services expense in base rates. The Company has also proposed to implement a credit to bills at the same time new rates become effective. As of the effective date of the new rates, fuel costs may be higher or lower than forecasted at the time of the filing, the reduction of the TCA rate should generate a decrease to the bill at that time and an approximate $9.3 million deferred credit will be included in rates to offset part of the rate increase for 12-months. The LFCR will likely increase slightly as of the rate effective date, but on July 1, 2017, approximately 1 year after the new rate effective date it could decrease or be a minimal increase depending on the outcome of this proceeding. **Exhibit CAJ-2** attempts to estimate the true bill impact a customer will realize as of the rate effective date.

IV. PROPOSED TARIFFS.

Q. Are you sponsoring the rate related tariffs UNS Electric is proposing in this rate case?

A. Yes. The proposed rate-related tariffs are attached to my Direct Testimony as **Exhibit CAJ-3** (clean copy) and **Exhibit CAJ-4** (redlined copy).

V. PRO FORMA ADJUSTMENTS.

A. Weather Normalization Adjustment.

Q. What is the purpose of a weather normalization adjustment?

A. Weather normalization is a standard adjustment commonly performed in rate cases. It is performed to provide a best estimate of test year sales, revenues, and costs as they would have been under normal weather conditions. Energy consumption for some of UNS Electric's customer classes are weather sensitive. For instance, a significant portion of energy usage in the summer comes from air conditioning load. Some summers, however, are warmer than normal and result in the Company selling more power and receiving more revenues than in a "normal" year. The reverse of this occurs when cooler than normal summer weather is experienced. The purpose of weather normalization is to "average" out these differences, so one can get a better sense as to what the Company is likely to receive in revenues during a normalized year.

Q. How has the weather normalization adjustment traditionally been calculated?

A. Historically, a typical industry practice was to use a variable known as heating degree days ("HDD") to measure heating load and another variable known as cooling degree days ("CDD") to measure cooling load. The theory has been that electric heating requirements are smaller when average daily temperatures are greater than 65 degrees Fahrenheit, and cooling requirements are smaller when the average daily temperatures are less than 65 degrees Fahrenheit. An HDD is measured by subtracting the average of the maximum and minimum temperature for that day from 65 degrees and a CDD as measured by subtracting 65 degrees from the average of the maximum and minimum temperature for that day. Negative results for both CDD and HDD calculations were set to zero. To obtain monthly HDD and CDD values, the daily values for each day of the month are summed.

The normal weather for each calendar month was assumed to be the average of the previous 10-years monthly CDD and HDD values as reported by the National Oceanic and Atmospheric Administration ("NOAA"). Actual monthly CDD and HDD for the UNS Electric service area were then compared with the normal weather.

Q. Is this the method you are proposing to use in this proceeding?

A. No. The Company has developed a more precise method to forecast sales which it has been using for its internal sales forecasts. The Company's refined method has consistently produced forecasts that are more closely aligned with actual results. Therefore, I am proposing it be used in this proceeding.

Q. Please describe the method you are proposing to use in this proceeding?

A. Much like the former method, NOAA-published information for the most recent 10 year period excluding the test year is utilized for each of the geographic territories served by UNS Electric:

Kingman, AZ for Kingman, AZ
Needles, CA for Havasu, AZ
Nogales, AZ for Nogales, AZ

Instead of two data points for each day being used as in the former method (the former method used the average of the high and low temperatures for each day to determine HDD or CDD for the day) the proposed method uses hourly average temperatures and hourly average dew points for each month. This data is directly out of the NOAA data base and is scrutinized through NOAA's validation process. Therefore it accurately reflects the actual temperatures in the area. Using 10 years of historical data allows the determination of a reasonable estimation of normal temperature and weather.

Q. Why change from the former Degree Day method to the proposed Average Temperature method?

A. The main purposes of the change in methodology are to more accurately capture the weather variability of sales and to isolate it from non-weather related effects. To accomplish this: a more accurate approximation of monthly weather is used, a trend variable is used to capture annual changes, and auto-regressive terms are used to capture non-weather related seasonal effects.

Heating and Cooling Degree days were initially used as an approximation to daily weather and had several advantages to average temperature in the pre-computer era since only two data points per day needed to be recorded and analyzed, thereby producing relatively easy calculations and requiring relatively small amounts of storage space. With the processing abilities of modern computers and available storage space, it is much easier, much less costly and much more accurate to use the more detailed average temperature (24 data points per day versus 2 data points per day) and average dew point data to approximate normal weather. Thus, it is appropriate to use the more accurate weather approximation since there is no required additional difficulty for their use.

Some other advantages to the proposed method result from the subjective definition of degree days. Degree days use a sense of "feel" to determine that heating dominates load below 65 degrees and cooling dominates load above 65 degrees. In reality, the Company's data indicates the residential class reacts to base temperatures of 62 degrees and the commercial class reacts to base temperatures closer to 50 degrees. Especially for the commercial class, this resulted in negative coefficients in winter months which the former method rejected and set to zero, thereby skewing the results and making them less accurate. The proposed method does not make subjective assertions as to which temperature heating or cooling load dominate, but instead allows the data to objectively establish that relationship.

Another disadvantage of degree days is they change linearly with temperature while the relationship of load to temperature is non-linear. To circumvent this problem, the degree day method used monthly weather coefficients where the new method accurately captures the non-linear relationship by using quadratic, and in some cases, cubic terms. The new method more robustly estimates the weather coefficients because each coefficient is based on more data points and they more accurately follow the load to temperature relationship. Further the model's accuracy was greatly improved but the model's complexity was actually reduced by eliminating variables. Thus, it is exceptionally clear that polynomial average weather coefficients are a superior weather variable compared to monthly degree days.

The proposed model also utilizes the effects of economic trends in its evaluation. Without a trend variable the regression process will attempt to explain some of the trend variation by changing the weather coefficients which reduces their ability to accurately capture how weather affects sales. Thus, if the goal is to isolate the weather effect as much as possible, as it should be, then it is best to include a statistically significant economic variable that helps to explain the annual changes in load.

The final change to the model was for the treatment of seasonal effects influencing load that are not caused by the weather. Examples of this include winter visitors, people flocking to Lake Havasu for spring break, or the timing of vegetable shipment through Nogales. All of these events occur roughly the same time each year and will influence load when they occur, but they are not events caused by the weather and should be isolated from the weather coefficients. In the degree day model, the use of monthly coefficients absorbed seasonal variations into the weather coefficient. Therefore, the degree day model did not properly separate weather from seasonal effects. In the average weather model, auto-regressive and moving average terms are used in conjunction with the weather variables in what is generally known as an ARIMAX model. The seasonal effects are handled very well by the auto-regressive and moving average terms which help to better isolate the weather from the seasonal effects. Thus, the average weather model estimates the true weather variability of load in a far superior way than the degree day model by isolating it from non-weather related seasonal effects.

Q. Was the weather normalization adjustment performed for all classes?

A. No. Weather normalization calculations were performed only for weather-sensitive residential and commercial classes, which were identified through regression analysis. Regression analysis revealed no statistically significant relationship between usage and weather for the industrial, mining, or street lighting classes; therefore, no weather adjustment is proposed for these classes.

Q. What did your calculations show?

A. Overall, weather was more extreme than normal during the test year (*i.e.*, warmer than normal in the summer, on average). Therefore, actual sales were higher than normal resulting in a "negative" adjustment to sales volumes and thus sales revenues.

B. <u>Customer Annualization Adjustment.</u>

Q. Please describe the customer annualization adjustment.

A. The customer annualization adjustment revises the number of test year bills and volumes to be consistent with the number of customers on the system at the end of the test year. The Company is proposing to use the same method that has been approved by this Commission in prior electric rate cases. The early months of the test year typically reflect more adjustment in the number of customers. For instance, the first month of the test year must be adjusted for 11 months of growth to reach adjusted test year end levels, whereas the eleventh month of the test year only requires one month of adjustment. Adjustments to the monthly volumes were made by multiplying the monthly customer differences by the normalized UPC for the month.

Q. Why is your customer annualization adjustment reflective of test year-end customer values, as opposed to some other adjusting point?

A. The customer annualization adjustment – when added to normalized billing determinants – should result in adjusted billing determinants that will reflect the bills and volumes at the time rates will be effective. Under the conditions described above and existing in this case, there is a nominal positive growth rate in the number of customers, and the last month of the test year reflects a customer count at or statistically close to the test year maximum. Therefore, the year-end adjustment technique results are the most accurate method to forecast the sales levels at the time new rates are effective. Also, adjusting to year-end values provides a larger reduction in the rate increase versus adjusting to other test year levels, such as a mid-year level. Accordingly, the year-end technique therefore is most effective in mitigating the rate increase UNS Electric is requesting in this application.

Q. What is the effect of the customer annualization adjustment on test year sales volumes?

A. As changes in the number of customers were reviewed and annualized, certain classes experienced increases, such as Residential and to some extent Small General Service, but the larger classes experienced reductions that will have a significant impact on sales levels due to the loss of two large customers in the current Large Power Service classes. Ultimately, the annualization of test year sales resulted in an overall reduction in the sales volumes used as billing determinants to determine annualized revenues.

Q. Why does the customer annualization adjustment have an impact on test year revenue and costs?

A. As I mentioned above, even small positive customer annualization adjustments can affect the number of customers, kWh consumed, and kW demand. Any increase, even a small one, means that adjusted billing determinants would typically be adjusted upward. So, increasing these billing determinants increases both adjusted revenues and expenses. More specifically, incremental customer growth will increase revenue and certain expenses. In evaluating the test year activity for this filing, the normal sales growth has been offset by the loss of the Company's largest customer and a second large customer. In this case, when all adjustments are made, the incremental net margin (the difference in revenue and expenses) is negative. Therefore, because the incremental net margin is negative, that will decrease the total operating income and increase the total revenue increase thereby increasing the revenue deficiency identified in this proceeding.

As part of analyzing the impact of customer-related changes, we must also consider the customers who changed tariff rates during the test year. Because these customers largely moved to rate schedules that generate less total revenues for the same level of test year kWh or kW, they result in a reduction to the test year's revenues and increase the requested increase to rates.

C. Transmission Expense Adjustment.

Q. Please describe the Company's treatment of transmission costs.

A. UNS Electric's retail rates include transmission costs based on the FERC-approved Open Access Transmission Tariff ("OATT") rates. The OATT rate authorized by the FERC is applicable to UNS Electric's transmission. UNS Electric's retail customers use the transmission system to bring energy from the source to the UNS Electric distribution system. Accordingly, transmission expenses reflect the OATT revenue requirement associated with native load.

VI. MISCELLANEOUS SERVICE FEES.

Q. Please describe the proposed changes in charges reflected on the "Statement of Charges".

A. The Company has reviewed the costs associated with providing other miscellaneous services to customers. This is being done during the rate case so any change in revenues resulting from changes to the rates can be accurately reflected in the Company's total revenue requirement. UNS Electric has calculated updated charges after quantifying the actual costs of providing these services. These charges were then applied to the actual number of units of each service occurring in the test year. The incremental increase produced by these changes will reduce the overall revenue requirement allocated to general rates based on the weighted proportion each rate class contributes to the total miscellaneous revenues. Please refer to attached **Exhibit CAJ-3** (Sheet No. 801), to see the specific charges the Company is proposing.

Q. Were any new miscellaneous service fees added?

A. Yes. The Company is proposing to establish a charge to provide customer usage data or interval data (if more than one request for standard usage data is made in a twelve-month period). The new charge is an hourly charge based on the time required to provide the data, is incremental to existing miscellaneous service fees and is included in the above miscellaneous revenue total. These charges can be found on **Exhibit CAJ-3** (Sheet No. 801).

Q. Will UNS Electric offer an opt-out option for those customers that do not want an Automated Meter Reading ("AMR") meter that uses radio frequency for meter readings?

A. Yes. The Company is proposing to add language to the Rules and Regulations that provide for the cost-based charges and conditions associated with a RES-01 customer choosing to either not have an AMR installed or to have an AMR unit replaced in order to have an "analog" meter measure their electrical usage.

Q. Have any UNS Electric customers requested to not have AMR meters installed?

A. Yes. So far, only 52 customers have told the Company they do not want an AMR unit installed.

Q. Why should these customers pay additional fees to not have an AMR unit installed?

A. Currently the Company is installing AMR units throughout its service territory. The UNS Electric service territory spreads over a substantial area of Arizona. The installation of AMR units allows for more automated meter reading and as a result a reduction in the cost to serve the customers. This reduction in cost is shared with all customers. AMR units also allow for better tracking of any fraudulent or unauthorized use as well, which provides savings to all customers. Meter technology is advancing and analog meters will soon be obsolete, thereby making them much more expensive to purchase and maintain than AMR units. This means that customers expressing a desire to keep analog meters will be costing the rest of the customers more and more each year. It is the Company's position that the other customers should not have to pay for added expenses created by these 50 or so customers who have decided to make a unique and more expensive choice.

Q. What other costs are associated with offering these customers the opportunity to opt-out of an AMR unit?

A. Because analog meters prevent the use of a fixed network system that remotely reads meters and provides the results to the Company remotely, actual meter readers will need to be dispatched on a regular basis to physically read the meters. The diverse nature of UNS Electric's territory could make this a very expensive activity, resulting incremental costs associated with labor, transportation, modified processes and equipment to maintain the manual reads and historical data, additional reporting requirements, etc. All of these are incremental costs that could be avoided if a standard AMR unit were installed. These costs should be paid by the customer with the desire to maintain soon to be obsolete equipment.

VII. MODIFICATIONS TO ADJUSTOR MECHANISMS.

Q. Is UNS Electric requesting any changes to its adjustor mechanisms in this case?

A. Yes. I will address the Company's proposed changes to how the PPFAC mechanism is administered to customers' rates and modifications to the LFCR mechanism. The Company's adjustor mechanisms will also be reset as certain costs are incorporated into UNS Electric's new base rates.

A. <u>Purchased Power and Fuel Adjustment Clause.</u>

Q. How is UNS Electric proposing to modify its PPFAC?

A. The PPFAC rate is currently adjusted monthly and charged to customers on a per kWh basis. The Company proposes to allocate the PPFAC costs, as currently calculated, on a percentage of the average base fuel rate established in this rate case. The monthly PPFAC charge will be a single percentage adjustment applied to all base fuel rates for all customer classes. I am also sponsoring the POA for the PPFAC, which is set forth in **Exhibit CAJ-5** in both clean and redline form.

Q. Why was the PPFAC percentage rate band changed from .83% per month to 1% per month?

A. The band was changed from .83% to 1% due to the reduction in fuel and purchased power expenses caused by the purchase of Gila River, as well as the low commodity prices implied in forward markets. UNS Electric's portion of Gila River will lower the amount of capacity payments made to third parties, reduce the amount of energy purchased, and reduce overall fuel expenses through wholesale power sales from the unit. Also, the current forecast utilizes a forward gas price of $3.03 per mmbtu of natural gas, which is lower than the gas costs expected when the .83% limit was established. The change to 1% movement per month was made in order to maintain equivalent movements in monthly rates when the expected reduction in the Total Average Retail Fuel and Purchased Power Rate is considered.

Q. **Why was the Base Rate Annual Adjustment added?**

A. The Base Rate Annual Adjustment was added to improve the correlation between actual Base Rate collections and the approved Base Rate. The variances between actual and approved Based Rate collections are driven by changing customer behavior and are best captured by incorporating actual observed customer usage patterns. The Base Rate Annual Adjustment is based upon prior year actual collections, and is modeled to collect only the amount approved by the Commission. This change will not affect the base rates reflected in the tariffs.

Q. **Will the Base Rate Annual Adjustment result in over collection of the Base Rate?**

A. No, the Base Rate is based upon prior year actual collections. When actual collections of the base are considered, there is an observable Base Rate Factor which calculates the ratio of actual collections to approved Base Rate collections. The Base Rate Adjuster is based on the Base Rate Factor, thus making the Base Rate Annual Adjustment entirely based upon the approval of the Base Rate and actual collections.

Q. **Is UNS Electric proposing revisions to the existing PPFAC POA?**

A. Yes. **Exhibit CAJ-5** is the proposed PPFAC POA and reflects my recommended changes mentioned above. The Company will prepare and provide conforming schedules.

Q. Why is UNS Electric proposing to modify the methodology for allocating the PPFAC to the various classes of customers?

A. The Company believes this method better aligns the changes in fuel costs with each rate classes' base fuel costs. For example, suppose an LPS customer's base fuel is $0.03 per kWh and the residential base fuel cost is $0.05 per kWh. Under the current method a ($0.0003) per kWh PPFAC change is a 1% decrease to the LPS customer's fuel costs, but is only a 0.6% decrease to the residential customer's fuel costs and visa-versa if it were a $0.0003 increase. By using an overall percentage based adjustment to base fuel costs; a 0.5% PPFAC increase will equate to a 0.5% increase for all classes..

B. <u>Lost Fixed Cost Recovery Mechanism.</u>

Q. Describe what additional fixed costs the Company proposes to recover through the LFCR.

A. Currently, the LFCR mechanism excludes recovery of the Company's fixed costs attributable to generation that are not recovered from customers when sales decline as a result of EE programs and DG systems developed pursuant to the EE Standard and REST. Additionally, the current LFCR only allows the recovery of 50% of the non-generation demand charges. The Company is proposing a change to the LFCR that will allow recovery of lost fixed costs attributable to generation and the full recovery of lost demand revenues.

Q. Why do you believe the generation related costs should be included in the value of the lost sales?

A. As the last rate case was settled the recommendation for approval was that the generation component should be excluded from the rates used to quantify the lost revenues. The Company agreed to this provision as part of the settlement, not because we agreed to the theory. Since that time, we have seen the magnitude of unrecovered revenues this inappropriate exclusion has caused and believe now is the time to add it back to the LFCR rates.

Q. Have you been able to recover any of the generation costs lost as the result of mandated EE or DG losses?

A. No. First, this is a vertically integrated utility. We own the generation and cannot simply get rid of it. Any generation owned by the Company is necessary to meet current and anticipated load (even EE or DG reduced load). There is no way to simply eliminate the cost. The cost was incurred to serve all customers, including the ones benefitting from EE and DG. They should be responsible for the costs. Second, there has been no wholesale market in the UNS Electric territory to market available generation, even at a discounted price. So that opportunity does not exist. Third, even if the Company was able to market its available generation, any revenue from that sale would go to the benefit of the PPFAC customers as a reduction to fuel costs, thereby reducing the end-users costs, but in no way aiding the Company in the recovery of its lost revenue.

Q. What is the Company's estimate of the lost revenues from compliance with the EE Standard and REST attributable to generation and the reduced demand charge?

A. Based on the kWh and kW losses reported in UNS Electric's 2015 LFCR filing, the Company's estimate is that the lost revenue associated with excluding the generation components and reducing the demand charges is approximately $573,000.

Q. What is the Company proposing to do to fix this under-recovery associated with removing 50% of the demand charge and all of the generation costs from the LFCR calculation?

A. The LFCR rates used in the schedules to quantify the dollar value assigned to the lost kWh and kW should be fully reflective of the non-fuel retail rate in each class. For tiered rates it should be the tail block rate or the weighted average of the tail block rates since that is the most likely level where lost sales would occur. Since the calculation of Demand related losses specifically identifies the actual amount of offset to the customer's peak demand, the Demand losses should be valued at the entire demand rate, not the current 50%.

Q. What other changes to the LFCR POA is the Company proposing?

A. Some clarifying language has been included to make it consistent with the intent of the process. The main example is for DG related losses, the current spreadsheet specifies that last year's total losses be added to this year's new total. However, since we are calculating DG losses based on current production meter reads less the production reads during the test year, it inherently captures most losses during that test year and does not need to include the carry-over from the prior year. We have removed that reference in the worksheets. Another example is our proposal to eliminate the residential LFCR Fixed Charge Option. As of the 2015 LFCR filing, there were no collections from this option. Therefore, the Company is proposing to remove the option of paying the LFCR as a fixed charge.

Another revision is the change from a 1% year-over-year cap to a 2% year-over-year cap. This was done because the current LFCR (with the 1% cap) removes generation related components and 50% of the demand in the rates for the calculation of lost revenue. When the generation costs and full demand charges are appropriately added back into the

LFCR, it would also be appropriate to increase the cap to 2%. While the Company agreed to the exclusion of generation in the settlement in the last rate case, the Company believes this unfairly understates the value of the lost sales and contributes to substantial under-recovery of lost revenues with no opportunity to recover them. Modifying the LFCR as proposed also promotes rate gradualism for customers.

The Company is also proposing to simplify the percentage-based LFCR Adjustment to be a single rate applied to customers' bills, rather than split the adjustment into two separate rates for EE and DG. Aside from these main changes, we have also updated the LFCR to add consistency between the POA and the related schedules, and we have also updated the schedules to include sections for any new rate classes proposed in this filing. The Company's proposed changes to the LFCR POA and schedules are included as **Exhibit CAJ-6** in both clean and redline form.

Q. **Does the Company wish to maintain the option for residential customers to choose to contribute to the LFCR in the form of a fixed charge instead of the volumetric rate?**

A. No. No customers have selected this option since it was adopted in the last rate case.

Q. **Has the LFCR resulted in a large surcharge to customers?**

A. No. First, the current annual 1% year-over-year cap reduces the impact of the LFCR to the customer. The combined EE and DG surcharge from the first UNS Electric LFCR filing was less than 0.6% and the 2015 LFCR filing will result in approximately a 0.3% incremental increase. These small increases would be slightly larger for the Company if the generation-related components were added back to the LFCR rates in order to include more of the lost revenues. Based on the 2015 LFCR filing, the Company estimates that the incremental increase would be higher by approximately 0.36%. However, our proposed increase to the basic service charges would also reduce the total dollars subject to adjustment in the LFCR.

Although UNS Electric anticipates any LFCR-related adjustments to be small, even with putting the Generation related costs back into the LFCR rate, the Company is proposing an annual year-over-year cap of 2% of total applicable revenues to provide for such predictability.

C. <u>Transmission Cost Adjustor.</u>

Q. Please describe how the TCA will be reset in this proceeding.

A. Yes. Consistent with methodology approved in UNS Electric's last rate case, the Company's 2015 OATT rate will be included in base rates and allocated to each rate class based on their contribution to the use of the transmission system. Upon the effective date of new base rates, the TCA rate will reflect the difference between the OATT rate included in base rates and the OATT rate in effect at that time.

VIII. OTHER.

Q. Are there any other topics or issues you would like to discuss?

A. Yes. As part of the Company's last rate case we agreed to evaluate the results of creating a rate for the largest customer class that was based on the allocation of demand costs on a 4CP basis. The Company performed this evaluation and determined not to propose such a rate at this time. Several factors led to this conclusion including (i) the loss of the largest LPS customer and other large customers within the LPS class, (ii) the redesign of the LGS and LPS rates, and (iii) the proposal to minimize the increase in rates to the larger classes.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Exhibit CAJ-1

UNSE
Marginal Cost Study (2013-2014)
Summary

CAJ-1
Schedule 1

Line	FERC A/C	Description	Residential Service	Small General Service
1		**Billing Determinants**		
2		kWh - Sales	823,953,185	118,683,796
3		Customer-Months	991,280	105,096
4		Demand		
5				
6		**Customer Installation Annual Carrying Costs ($)**		
7	370	Meters	$ 39.95	$ 47.63
8	369	Services - Overhead/Underground	$ 10.37	$ 9.77
9	368	Line Transformers	$ 166.17	$ 166.17
10	365-367	Conductors & Devices - Overhead/Underground	$ 90.97	$ 268.58
11	364	Poles, Towers & Fixtures	$ 234.94	$ 621.06
12	389-398	General Plant	$ 0.72	$ 1.23
13		**Subtotal: Customer Annual Carrying Costs**	**$ 543.12**	**$ 1,114.45**
14				
15		**Customer O&M Costs**		
16	902	Meter Reading Expenses	$ 7.03	$ 7.03
17	903	Customer Records & Collection Expenses	$ 30.37	$ 30.37
18	904	Uncollectible Accounts	$ 2.94	$ 5.09
19	905	Customer Accounts Expenses Supervision	$ (0.03)	$ (0.03)
20	908	Customer Assistance Expenses	$ 1.27	$ 1.27
21	909	Informational and Instructional Advertising Exp.	$ 4.29	$ 4.29
22	910	Misc. Customer Service & Informational Exp.	$ 0.03	$ 0.03
23	920-935	Customer A&G Costs	$ 32.81	$ 61.85
24		**Subtotal: Customer O&M Costs**	**$ 78.70**	**$ 109.89**
25				
26		**Marginal Cost per Customer (Annual)**	**$ 621.82**	**$ 1,224.34**
27		**Marginal Cost per Customer (Per Month)**	**$ 51.82**	**$ 102.03**
28		**Marginal Revenue Requirement**	**$ 51,366,450**	**$ 10,722,791**
29				
30		**Current Rates (Customer Charge)**	$ 10.00	$ 14.50
31		**Deficiency**	**$ 41,453,650**	**$ 9,198,899**

UNSE
Marginal Cost Study (2013-2014)
Customer Installation Investment Costs

CAJ-1
Schedule 2

Line	FERC A/C	Description	Residential Service	Small General Service
1		**Billing Determinants**		
2		kWh - Sales	823,953,185	118,683,796
3		Customer-Months	991,280	105,096
4		Demand		
5				
6	370	**Meters**		
7		Investment ($/Meter)	$ 208.00	$ 248.00
8		ECCR	19.20%	19.20%
9		Unit Annual Carrying Cost ($/Meter)	$ 39.95	$ 47.63
10		Total Annual Carrying Cost ($)	$ 3,299,815	$ 417,127
11				
12	369	**Services - Overhead/Underground**		
13		Unit Cost ($/Ft, New Service)	$ 1.47	$ 1.47
14		Footage (Ft)	87.00	82.00
15		Investment ($/Meter)	$ 127.89	$ 120.54
16		ECCR	8.11%	8.11%
17		Unit Annual Carrying Cost ($/Meter)	$ 10.37	$ 9.77
18		Total Annual Carrying Cost ($)	$ 856,621	$ 85,600
19				
20	368	**Line Transformers**		
21		Unit Cost ($/Transformer, New)	$ 1,967	$ 1,967
22		Transformers per Customer (Transfer/Cust.)	1.00	1.00
23		Investment ($/Cust.)	$ 1,967	$ 1,967
24		ECCR	8.45%	8.45%
25		Unit Annual Carrying Cost ($/Cust.)	$ 166.17	$ 166.17
26		Total Annual Carrying Cost ($)	$ 13,727,057	$ 1,455,349
27				
28				

UNSE CAJ-1

Marginal Cost Study (2013-2014) Schedule 2

Customer Installation Investment Costs

Line	FERC A/C	Description	Residential Service	Small General Service
29	365-367	**Conductors & Devices - Overhead/Underground**		
30		OH Conductor - Unit Cost ($/Ft)	$ 1.90	$ 1.90
31		OH Conductor - Footage (Ft/Install)	1,200	760
32		OH Conductor Investment ($/Install)	$ 2,280	$ 1,444
33		UG Conductor - Unit Cost ($/Ft)	$ 3.04	$ 3.04
34		UG Conductor - Footage (Ft/Install)	510	570
35		UG Conductor Investment ($/Install)	$ 1,550	$ 1,733
36		OH+UG Conductor Investment ($/Install)	$ 3,830	$ 3,177
37		% Customers that require new facilities	25.0%	89.0%
38		Avg. Conductor Investment ($/Cust.)	$ 958	$ 2,827
39		ECCR	9.50%	9.50%
40		Unit Annual Carrying Cost ($/Cust.)	$ 90.97	$ 268.58
41		Total Annual Carrying Cost ($)	$ 7,514,329	$ 2,352,208
42				
43	364	**Poles, Towers & Fixtures**		
44		Unit Cost ($/Pole)	$ 1,488	$ 1,488
45		Number of Poles per Customer	4	2
46		Investment - Poles ($/Install)	$ 5,952	$ 2,976
47		Investment - Fixtures ($/Install)	$ 5,608	$ 5,608
48		Investment - Poles + Fixtures ($/Install)	$ 11,560	$ 8,584
49		% Customers that require new facilities	25.0%	89.0%
50		Avg Investment - Poles + Fixtures ($/Cust.)	$ 2,890	$ 7,639
51		ECCR	8.13%	8.13%
52		Unit Annual Carrying Cost ($/Cust.)	$ 234.94	$ 621.06
53		Total Annual Carrying Cost ($)	$ 19,407,658	$ 5,439,248
54				
55	389-398	**General Plant**		
56		General Plant - ECOSS Customer Allocation	$ 7,220,290	$ 1,312,341
57		Less: Accumulated Depreciation	$ (3,342,754)	$ (607,570)
58		Net General Plant - Customer Allocation	$ 3,877,536	$ 704,771
59		Return on Ratebase (Pre Tax)	11.1%	11.1%
60		Return on Ratebase (Pre Tax)	$ 430,311	$ 78,212
61		Depreciation Expence	$ 283,425	$ 51,515
62		Total Annual Carrying Costs ($)	$713,736	$129,727
63		Unit Annual Carrying Costs ($/Cust.)	$ 0.72	$ 1.23

UNSE
Marginal Cost Study (2013-2014)
Customer O&M Costs

CAJ-1
Schedule 3

Line	FERC A/C	Description	Residential Service	Small General Service
1		**Billing Determinants**		
2		kWh - Sales	823,953,185	118,683,796
3		Customer-Months	991,280	105,096
4				
5	902	**Meter Reading Expenses**		
6		Meter Reading Expenses	$ 580,400	$ 61,534
7		Expenses per customer	$ 7.03	$ 7.03
8				
9	903	**Customer Records & Collection Expenses**		
10		Customer Records & Collection Expenses	$ 2,509,015	$ 266,007
11		Expenses per customer	$ 30.37	$ 30.37
12				
13	904	**Uncollectible Accounts**		
14		Uncollectible Accounts	$ 242,660	$ 44,550
15		Expenses per customer	$ 2.94	$ 5.09
16				
17	905	**Customer Accounts Expenses Supervision**		
18		Customer Accounts Expenses Supervision	$ (2,199)	$ (233)
19		Expenses per customer	$ (0.03)	$ (0.03)
20				
21	908	**Customer Assistance Expenses**		
22		Customer Assistance Expenses	$ 105,145	$ 11,147
23		Expenses per customer	$ 1.27	$ 1.27
24				
25	909	**Informational and Instructional Advertising Exp.**		
26		Informational and Instructional Advertising Exp.	$ 354,054	$ 37,537
27		Expenses per customer	$ 4.29	$ 4.29
28				
29	910	**Misc. Customer Service & Informational Exp.**		
30		Misc. Customer Service & Informational Exp.	$ 2,167	$ 230
31		Expenses per customer	$ 0.03	$ 0.03
32				
33	920-935	**Administrative and General Expense**		
34		Administrative and General Expense	$ 5,515,882	$ 942,575
35		A&G Expense - Customer Allocation	$ 2,710,250	$ 541,675
36		Expenses per customer	$ 32.81	$ 61.85
37				
38		**Total Customer Expense**	$ 78.70	$ 109.89

Exhibit CAJ-2

Exhibit CAJ-2

UNS ELECTRIC, INC.
BILL IMPACTS
TEST PERIOD ENDING DECEMBER 31, 2014

Line No.	Class Description	Customer Counts To-date (Mar 2015)	TEST YEAR ADJUSTED - FUEL TRUE-UP AND MARGIN INCREASE: Annual Bill Change	Monthly Bill Change	Percent Change to Total Bill With Fuel Increase	TEST YEAR ADJUSTED WITH MARGIN INCREASE, FUEL/PPAFC TRU-UP, TCA AND DEFERRED CREDIT: Annual Bill Change	Monthly Bill Change	Percent Change to Total Bill With Fuel Increase	COS RETURNS
1	Residential	74,788	$118.26	$9.86	**11.62%**	$23.82	$1.99	**2.26%**	
2	Residential CARES	6,026	$61.02	$5.09	**8.00%**	($16.25)	($1.35)	**-2.05%**	
	Residential CARES-M	289	$69.42	$5.79	**6.89%**	($31.97)	($2.66)	**-3.06%**	6.00%
3	Residential TOU	258	$222.64	$18.55	**19.88%**	$108.66	$9.06	**9.34%**	
4	Residential TOU Super Peak	2	$223.84	$18.65	**19.43%**	$105.90	$8.83	**8.86%**	
5	Small General Service	8,732	$187.81	$15.65	**12.92%**	$59.89	$4.99	**3.99%**	6.40%
6	Small General Service TOU	8	$228.63	$19.05	**9.70%**	$9.03	$0.75	**0.37%**	
7	Interruptible Service	28	$13,833.34	$1,152.78	**15.85%**	$7,561.90	$630.16	**8.74%**	
8	Medium General Service	1321	($1,515.11)	($126.26)	**-4.65%**	($3,127.79)	($260.65)	**-9.67%**	
9	Medium General Service TOU	8	($2,123.34)	($176.95)	**-2.62%**	($1,451.94)	($121.00)	**-1.81%**	
10	Large General Service	10	($35,007.40)	($2,917.28)	**-7.05%**	($64,587.76)	($5,382.31)	**-13.09%**	12.96%
11	Large General Service (Formally LPS)	7	($48,807.40)	($4,067.28)	**-9.56%**	($78,387.76)	($6,532.31)	**-15.45%**	
12	Large General Service TOU	2	($19,907.58)	($1,658.97)	**-2.96%**	($61,483.02)	($5,123.59)	**-9.20%**	
13	Large Power Service	3	($5,904.66)	($492.06)	**-0.44%**	($104,261.34)	($8,688.45)	**-7.79%**	9.06%
14	Large Power Service TOU	1	$3,544.56	$295.38	**0.17%**	($209,410.02)	($17,450.84)	**-9.67%**	
15	Lighting Service	2,377	$29.28	$2.44	**18.36%**	$26.40	$2.20	**16.55%**	7.87%
16	TOTAL COMPANY	93,860							7.93%

Exhibit CAJ-3

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 101
Superseding:

Residential Service (RES-01)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to electrical equipment that causes excessive voltage fluctuations.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE AND ENERGY CHARGES

Basic Service Charge: $20.00 per month

Energy Charges (per kWh):

	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
0 - 400 kWh	$0.030810	$0.049260	Varies	$0.080070
Over 400 kWh	$0.050810	$0.049260	Varies	$0.100070

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

MONTHLY CUSTOMER ASSISTANCE RESIDENTIAL ENERGY SUPPORT (CARES) DISCOUNT:
This discount is only available to new and eligible CARES Customers whose monthly bill shall be in accordance to the rate above except that a discount of $10.00 per month shall be applied. No CARES discount will be applied that will reduce the bill to less than zero.

CARES ELIGIBILITY

1. The UNS Electric account must be in the Customer's name applying for a CARES discount.
2. Applicant must be a UNS Electric residential Customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on UNS Electric's website at www.uesaz.com or contact a UNS Electric customer care representative.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 101-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 1.38 per month
Meter Reading	$ 0.89 per month
Billing & Collection	$ 6.01 per month
Customer Delivery	$11.72 per month
Total	$20.00 per month

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	
0 – 400 kWh	$0.009160
Over 400 kWh	$0.029160
Generation Capacity	$0.010980
Transmission	$0.010670

Power Supply Charges:

Component	
Base Power Supply (per kWh)	$0.049260
PPFAC (%) (see Rider-1 for current rate)	Varies

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 102
Superseding:

Residential Service Time-of-Use (RES-01 TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to electrical equipment that causes excessive voltage fluctuations.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

Service under this rate will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE AND ENERGY CHARGES

Basic Service Charge: $20.00 per month

Energy Charges (per kWh)

Summer (May – October)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 – 400 kWh				
On-Peak	$0.030810	$0.101110	Varies	$0.131920
Off-Peak	$0.030810	$0.033900	Varies	$0.064710
Over 400 kWh				
On-Peak	$0.050810	$0.101110	Varies	$0.151920
Off-Peak	$0.050810	$0.033900	Varies	$0.084710

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 102-1
Superseding:

Winter (November – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 – 400 kWh				
On-Peak	$0.030810	$0.098960	Varies	$0.129770
Off-Peak	$0.030810	$0.033579	Varies	$0.064389
Over 400 kWh				
On-Peak	$0.050810	$0.098960	Varies	$0.149770
Off-Peak	$0.050810	$0.033579	Varies	$0.084389

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

Calculation of Tiered (Block) Usage by TOU Period:

Step 1: Calculate percent usage by TOU period.
Step 2: Calculate the kWh usage by tier (block).
Step 3: Multiply percent usage by TOU period by kWh usage by tier to obtain tiered usage by TOU period.

Example: A Customer using 2,000 kWh in a month, with 20% on-peak usage and 80% off-peak usage will have 80 kWh in on-peak first tier and 320 kWh in on-peak second tier, and will have 320 kWh in off-peak first tier and 1280 kWh in off-peak second tier.

kWh	On-Peak	Off-Peak	Total
0 – 400 kWh	80	320	400
Over 400 kWh	320	1,280	1,600
Total	400	1,600	2,000

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 5:00 a.m. - 9:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

UniSource Energy SERVICES

UNS Electric, Inc.

Original Sheet No.: 102-2
Superseding:

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 1.38 per month
Meter Reading	$ 0.89 per month
Billing & Collection	$ 6.01 per month
Customer Delivery	$11.72 per month
Total	$20.00 per month

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	
0 – 400 kWh	$0.009160
Over 400 kWh	$0.029160
Generation	$0.010980
Transmission	$0.010670

Power Supply Charges:

Component	
Base Power Supply Summer (May – October) On-Peak (per kWh)	$0.101110
Base Power Supply Summer (May – October) Off-Peak (per kWh)	$0.033900
Base Power Supply Winter (November – April) On-Peak (per kWh)	$0.098960
Base Power Supply Winter (November – April) Off-Peak (per kWh)	$0.033579
PPFAC (%) (see Rider-1 for current rate)	Varies

Customer Assistance Residential Energy Support (CARES-F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this rate.

APPLICABILITY
To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to electrical equipment that causes excessive voltage fluctuations.

ELIGIBILITY
1. The UNS Electric account must be in the Customer's name applying for a CARES discount.
2. Applicant must be a UNS Electric residential Customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on UNS Electric's website at www.uesaz.com or contact a UNS Electric customer care representative.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE AND ENERGY CHARGES

Basic Service Charge: $9.00 per month

Energy Charges (per kWh):

	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
0 - 400 kWh	$0.030810	$0.049260	Varies	$0.080070
Over 400 kWh	$0.050810	$0.049260	Varies	$0.100070

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

MONTHLY CUSTOMER ASSISTANCE RESIDENTIAL ENERGY SUPPORT (CARES) DISCOUNT

The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the Basic Service Charge, Delivery Charges, and Power Supply Charges:
0 – 300 kWh	30%
301 – 600 kWh	20%
601- 1,000 kWh	10%
Over 1,000 kWh	$10.00

No CARES discount will be applied that will reduce the bill to less than zero.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 103-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$0.62 per month
Meter Reading	$0.40 per month
Billing & Collection	$2.71 per month
Customer Delivery	$5.27 per month
Total	$9.00 per month

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	
0 - 400 kWh	$0.009160
Over 400 kWh	$0.029160
Generation Capacity	$0.010980
Transmission	$0.010670

Power Supply Charges:

Component	
Base Power Supply (per kWh)	$0.049260
PPFAC (%) (see Rider-1 for current rate)	Varies

Customer Assistance Residential Energy Support Low Income Medical Life Support Program (CARES-M-F)

AVAILABILITY
New Customers, including those who move are not eligible for service under this rate.

APPLICABILITY
To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

This CARES Low Income Medical Life Support Program is available to all qualified CARES residential customers who are medically life-support dependent and who meet the eligibility requirements.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to electrical equipment that causes excessive voltage fluctuations.

ELIGIBILITY REQUIREMENTS
To be eligible for the CARES Low Income Medical Life Support Program, a Customer must meet the following requirements:

A. Require the use of medical equipment that is considered essential for sustaining life and is operated at the residence;
B. Submit to UNS Electric a statement signed by the attending physician that verifies that the customer is medically life-support dependent and states the type of essential medical equipment in use at the residence; and
C. Submit to UNS Electric verification by the physician to remain eligible for the program beyond two years.

The following equipment is representative of that which may be qualified as being essential under the program:

- Ventilator
- Oxygen concentrator
- Peritoneal Dialysis Cycler
- Hemo Dialysis Equipment
- Feeding Pump
- Infusion Pump
- Suction Machine
- Small Volume Nebulizer

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE AND ENERGY CHARGES

Basic Service Charge: $9.00 per month

Energy Charges (per kWh):

	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 - 400 kWh	$0.030810	$0.049260	Varies	$0.080070
Over 400 kWh	$0.050810	$0.049260	Varies	$0.100070

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

CARES LOW INCOME MEDICAL LIFE SUPPORT PROGRAM DISCOUNT
The monthly bill for customers eligible under the CARES Low Income Medical Life Support Program shall be computed in accordance to the rates above including the following discount:

For Bills with Usage of:	Monthly Discount will be applied to the Basic Service Charge, Delivery Charges, and Power Supply Charges:
0 – 600 kWh	30%
601 – 1,200 kWh	20%
1,201- 2,000 kWh	10%
Over 2,000 kWh	$10.00

No CARES discount will be applied that will reduce the bill to less than zero.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$0.62 per month
Meter Reading	$0.40 per month
Billing & Collection	$2.71 per month
Customer Delivery	$5.27 per month
Total	$9.00 per month

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	
0 - 400 kWh	$0.009160
Over 400 kWh	$0.029160
Generation Capacity	$0.010980
Transmission	$0.010670

Power Supply Charges:

Component	
Base Power Supply (per kWh)	$0.049260
PPFAC (%) (see Rider-1 for current rate)	Varies

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 105
Superseding:

Residential Service Time-of-Use Super Peak (RES-01 TOU SuperPeak)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to electrical equipment that causes excessive voltage fluctuations.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

Service under this rate will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE AND ENERGY CHARGES

Basic Service Charge: $20.00 per month

Energy Charges (per kWh):

Summer (May – October)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 – 400 kWh				
On-Peak	$0.030810	$0.149700	Varies	$0.180510
Off-Peak	$0.030810	$0.038250	Varies	$0.069060
Over 400 kWh				
On-Peak	$0.050810	$0.149700	Varies	$0.200510
Off-Peak	$0.050810	$0.038250	Varies	$0.089060

Winter (November – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 – 400 kWh				
On-Peak	$0.030810	$0.149700	Varies	$0.180510
Off-Peak	$0.030810	$0.038250	Varies	$0.069060
Over 400 kWh				
On-Peak	$0.050810	$0.149700	Varies	$0.200510
Off-Peak	$0.050810	$0.038250	Varies	$0.089060

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

Calculation of Tiered (Block) Usage by TOU Period:

Step 1: Calculate percent usage by TOU period.
Step 2: Calculate the kWh usage by tier (block).
Step 3: Multiply percent usage by TOU period by kWh usage by tier to obtain tiered usage by TOU period.
Example: A Customer using 2,000 kWh in a month, with 20% on-peak usage and 80% off-peak usage will have 80 kWh in on-peak first tier and 320 kWh in on-peak second tier, and will have 320 kWh in off-peak first tier and 1280 kWh in off-peak second tier.

kWh	On-Peak	Off-Peak	Total
0 – 400 kWh	80	320	400
Over 400 kWh	320	1,280	1,600
Total	400	1,600	2,000

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 5:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak period is 5:00 p.m. - 8:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 1.38 per month
Meter Reading	$ 0.89 per month
Billing & Collection	$ 6.01 per month
Customer Delivery	$11.72 per month
Total	$20.00 per month

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	
0 – 400 kWh	$0.009160
Over 400 kWh	$0.029160
Generation	$0.010980
Transmission	$0.010670

Power Supply Charges:

Component	
Base Power Supply Summer (May – October) On-Peak (per kWh)	$0.149700
Base Power Supply Summer (May – October) Off-Peak (per kWh)	$0.038250
Base Power Supply Winter (November – April) On-Peak (per kWh)	$0.149700
Base Power Supply Winter (November – April) Off-Peak (per kWh)	$0.038250
PPFAC (%) (see Rider-1 for current rate)	Varies

Residential Service Demand (RES-01 Demand)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

This rate is optional for Residential Service Customers, but mandatory for non-Time-of-Use Residential Service Customers taking service under Rider-10, Net Metering for Certain Partial Requirements Service (NM-PRS), Post June 1, 2015.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to electrical equipment that causes excessive voltage fluctuations.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND, AND ENERGY CHARGES

Basic Service Charge: $20.00 per month

Demand Charges (per kW):

	Delivery Services-Demand
0 - 7 kW	$6.00
Over 7 kW	$9.95

Energy Charge (per kWh)

	Delivery Services-Energy	Power Supply Charges[1]		Total[2]
		Base Power	PPFAC[1]	
All kWh	$0.010000	$0.049260	Varies	$0.059260

1. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.
2. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

BILLING DEMAND
The monthly billing demand shall be the maximum 1-hour measured demand in the billing month.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 106-2
Superseding: ____________

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 1.38 (per month)
Meter Reading	$ 0.89 (per month)
Billing & Collection	$ 6.01 (per month)
Customer Delivery	$11.72 (per month)
Total	$20.00 (per month)

Demand Charges (per kW) (Unbundled):

Component	
Demand Delivery	
0 – 7 kW	$2.89
Over 7 kW	$6.84
Generation Capacity	$1.58
Transmission	$1.53

Energy Charge Components (per kWh) (Unbundled):

Component	
Local Delivery	$0.010000

Power Supply Charges:

Component	
Base Power Supply (per kWh)	$0.049260
PPFAC (%) (see Rider-1 for current rate)	Varies

UniSource Energy SERVICES

UNS Electric, Inc.

Original Sheet No.: 107
Superseding:

Residential Service Demand Time-of-Use (RES-01 Demand TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

This rate is optional for Residential Service Time-of-Use Customers, but mandatory for Residential Service Time-of-Use Customers taking service under Rider-10, Net Metering for Certain Partial Requirements Service (NM-PRS), Post June 1, 2015.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to electrical equipment that causes excessive voltage fluctuations.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND, AND ENERGY CHARGES

Basic Service Charge: $20.00 per month

Demand Charges (per kW)

	Delivery Services-Demand
0 - 7 kW	$6.00
Over 7 kW	$9.95

Energy Charges (per kWh)

Summer (May – October)	Delivery Services-Energy	Power Supply Charges[1] Base Power	PPFAC[1]	Total[2]
All kWh				
On-Peak	$0.010000	$0.101110	Varies	$0.111110
Off-Peak	$0.010000	$0.033900	Varies	$0.043900

Winter (November – April)	Delivery Services-Energy	Power Supply Charges[1] Base Power	PPFAC[1]	Total[2]
All kWh				
On-Peak	$0.010000	$0.098960	Varies	$0.108960
Off-Peak	$0.010000	$0.033579	Varies	$0.043579

1. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.
2. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

BILLING DEMAND
The monthly billing demand shall be the maximum 1-hour measured demand in the billing month.

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 5:00 a.m. - 9:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

UniSource Energy SERVICES

UNS Electric, Inc.

Original Sheet No.: 107-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 1.38 per month
Meter Reading	$ 0.89 per month
Billing & Collection	$ 6.01 per month
Customer Delivery	$11.72 per month
Total	$20.00 per month

Demand Charge Components (per kW) (Unbundled):

Component	
Demand Delivery	
0 – 7 kW	$2.89
Over 7 kW	$6.84
Generation Capacity	$1.58
Transmission	$1.53

Energy Charge Components (per kWh) (Unbundled):

Component	
Local Delivery	$0.010000

Power Supply Charges:

Component	
Base Power Supply Summer (May – October) On-Peak (per kWh)	$0.101110
Base Power Supply Summer (May – October) Off-Peak (per kWh)	$0.033900
Base Power Supply Winter (November – April) On-Peak (per kWh)	$0.098960
Base Power Supply Winter (November – April) Off-Peak (per kWh)	$0.033579
PPFAC (%) (see Rider-1 for current rate)	Varies

Small General Service (SGS-10)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rates, when all energy is supplied at one point of delivery and through one metered service.

The supply of electric service under a residential rate to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the electricity used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters. Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises must be classified as non-residential and the appropriate general service rate will be applied.

Not applicable to resale, breakdown, standby, or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

In the event a Customer meets or exceeds 12,000 kWh in two consecutive months the Customer will be moved to the Medium General Service tariff.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE AND ENERGY CHARGES

Basic Service Charge: $30.00 per month

Energy Charges (per kWh):

	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
0 - 400 kWh	$0.039497	$0.048610	Varies	$0.088107
401 – 7,500 kWh	$0.049497	$0.048610	Varies	$0.098107
Over 7,500 kwh	$0.086950	$0.048610	Varies	$0.135560

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 201-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Basic Service Charge Components (Unbundled):

Description	Basic Service Charge
Meter Services	$ 1.18 per month
Meter Reading	$11.51 per month
Billing & Collection	$ 5.17 per month
Customer Delivery	$12.14 per month
Total	$30.00 per month

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	Rate
0 – 400 kWh	$0.018127
401 – 7,500 kWh	$0.028127
Over 7,500 kWh	$0.065580
Generation Capacity	$0.010840
Transmission	$0.010530

Power Supply Charges:

Component	Rate
Base Power Supply (per kWh)	$0.048610
PPFAC (%) (see Rider-1 for current rate)	Varies

Small General Service Time-of-Use (SGS-10 TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific Rates, when all energy is supplied at one point of delivery and through one metered service.

The supply of electric service under a residential Rate to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the electricity used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters. Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises must be classified as non-residential and the appropriate general service rate will be applied.

Service under this rate will commence when the appropriate meter has been installed.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

In the event a Customer meets or exceeds 12,000 kWh in two consecutive months the Customer will be moved to the Medium General Service Time-of-Use tariff.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 202-1
Superseding:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE AND ENERGY CHARGES

Basic Service Charge: $30.00 per month

Energy Charges (per kWh):

Summer (May – October)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 - 400 kWh				
On-Peak	$0.039497	$0.126510	Varies	$0.166007
Off-Peak	$0.039497	$0.033010	Varies	$0.072507
401 – 7,500 kWh				
On-Peak	$0.049497	$0.126510	Varies	$0.176007
Off-Peak	$0.049497	$0.033010	Varies	$0.082507
Over 7,500 kWh				
On-Peak	$0.086950	$0.126510	Varies	$0.213460
Off-Peak	$0.086950	$0.033010	Varies	$0.119960

Winter (November – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 - 400 kWh				
On-Peak	$0.039497	$0.108510	Varies	$0.148007
Off-Peak	$0.039497	$0.032910	Varies	$0.072407
401 – 7,500 kWh				
On-Peak	$0.049497	$0.108510	Varies	$0.158007
Off-Peak	$0.049497	$0.032910	Varies	$0.082407
Over 7,500 kWh				
On-Peak	$0.086950	$0.108510	Varies	$0.195460
Off-Peak	$0.086950	$0.032910	Varies	$0.119860

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month

Filed By:	Kentton C. Grant	Rate:	SGS-10 TOU
Title:	Vice President	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	Pending

Calculation of Tiered (Block) Usage by TOU Period:

Step 1: Calculate percent usage by TOU period.
Step 2: Calculate the kWh usage by tier (block).
Step 3: Multiply percent usage by TOU period by kWh usage by tier to obtain tiered usage by TOU period.
Example: A Customer using 10,000 kWh in a month, with 20% on-peak usage and 80% off-peak usage will have 80 kWh in on-peak first tier, 1,420 kWh in on-peak second tier and 500 kWh in on-peak third tier and 320 kWh in off-peak first tier, 5,680 kWh in off-peak second tier and 2,000 kWh in off-peak third tier.

kWh	On-Peak	Off-Peak	Total
0 – 400 kWh	80	320	400
401 – 7,500 kWh	1,420	5,680	7,100
Over 7,500 kWh	500	2,000	2,500
Total	2,000	8,000	10,000

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 5:00 a.m. - 9:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 1.18 per month
Meter Reading	$11.51 per month
Billing & Collection	$ 5.17 per month
Customer Delivery	$12.14 per month
Total	$30.00 per month

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	
0 – 400 kWh	$0.018127
401 – 7,500 kWh	$0.028127
Over 7,500 kWh	$0.065580
Generation Capacity	$0.010840
Transmission	$0.010530

Power Supply Charges:

Component	
Base Power Supply Summer (May – October) On-Peak (per kWh)	$0.126510
Base Power Supply Summer (May – October) Off-Peak (per kWh)	$0.033010
Base Power Supply Winter (November – April) On-Peak (per kWh)	$0.108510
Base Power Supply Winter (November – April) Off-Peak (per kWh)	$0.032910
PPFAC (%) (see Rider -1 for current rate)	Varies

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 203
Superseding:

Time-of-Use for Small General Service Schools (SGS-10 TOU-S)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all private and public schools (K-12) unless otherwise addressed by specific Rates, when all energy is supplied at one point of delivery and through one metered service.

Service under this Rate will commence when the appropriate meter has been installed.

Only available to Customers with imputed demand less than 500 KW.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge: $16.50 per month

Energy Charges (per kWh):

Summer (May – October)	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
0 - 400 kWh				
On-Peak	$0.030176	$0.137405	Varies	$0.167581
Off-Peak	$0.030176	$0.047405	Varies	$0.077581
401 – 7,500 kWh				
On-Peak	$0.043176	$0.137405	Varies	$0.180581
Off-Peak	$0.043176	$0.047405	Varies	$0.090581
Over 7,500 kWh				
On-Peak	$0.076042	$0.137405	Varies	$0.213447
Off-Peak	$0.076042	$0.047405	Varies	$0.123447

Winter (November – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 - 400 kWh				
On-Peak	$0.030176	$0.137405	Varies	$0.167581
Off-Peak	$0.030176	$0.039185	Varies	$0.069361
401 – 7,500 kWh				
On-Peak	$0.043176	$0.137405	Varies	$0.180581
Off-Peak	$0.043176	$0.039185	Varies	$0.082361
Over 7,500 kWh				
On-Peak	$0.076042	$0.137405	Varies	$0.213447
Off-Peak	$0.076042	$0.039185	Varies	$0.115227

1. Delivery Services-Energy is a bundled charge that includes: Transmission, Sub-transmission, Local Delivery Energy and Production not included in Power Supply.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

TIME-OF-USE PERIODS

The Summer On-Peak period is 3:00 p.m. to 7:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 5:00 a.m. - 9:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this Rate.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Customer Charge Components (Unbundled):

Description	Customer Charge
Meter Services	$ 2.69 per month
Meter Reading	$ 5.24 per month
Billing & Collection	$ 7.23 per month
Customer Delivery	$ 1.34 per month
Total	$16.50 per month

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	Rate
0 – 400 kWh	$0.013662
401 – 7,500 kWh	$0.026662
Over 7,500 kWh	$0.059528
Generation Capacity	$0.010400
Transmission	$0.006114

Power Supply Charges (per kWh):

Component	Rate
Base Power Supply Summer (May – October) On-Peak	$0.137405
Base Power Supply Summer (May – October) Off-Peak	$0.047405
Base Power Supply Winter (November – April) On-Peak	$0.137405
Base Power Supply Winter (November – April) Off-Peak	$0.039185
PPFAC (see Rider -1 for current rate)	Varies

Small General Service Demand (SGS-10 Demand)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rates, when all energy is supplied at one point of delivery and through one metered service.

This rate is optional for Small General Service Customers, but mandatory for non-Time-of-Use Small General Service Customers taking service under Rider-10, Net Metering for Certain Partial Requirements Service (NM-PRS), Post June 1, 2015.

The supply of electric service under a residential rate to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the electricity used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters. Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises must be classified as non-residential and the appropriate general service rate will be applied.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

In the event measured kW meets or exceeds 40 kW, the Customer will be moved to the Medium General Service rate.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND, AND ENERGY CHARGES

Basic Service Charge: $30.00 per month

Demand Charges (per kW)

	Delivery Services-Demand
0 - 15 kW	$6.85
Over 15 kW	$7.85

Energy Charges (per kWh)

	Delivery Services-Energy	Power Supply Charges[1]		Total[2]
		Base Power	PPFAC[1]	
0 – 7,500 kWh	$0.011100	$0.048610	Varies	$0.059710
Over 7,500 kWh	$0.055000	$0.048610	Varies	$0.103610

1. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.
2. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

BILLING DEMAND
The monthly billing demand shall be the maximum 1-hour measured demand in the billing month.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 1.18 per month
Meter Reading	$ 11.51 per month
Billing & Collection	$ 5.17 per month
Customer Delivery	$12.14 per month
Total	$30.00 per month

Demand Charge Components (per kW) (Unbundled):

Demand Delivery	
0 – 15 kW	$3.77
Over 15 kW	$4.77
Generation Capacity	$1.56
Transmission	$1.52

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	
0 – 7,500 kWh	$0.011100
Over 7,500 kWh	$0.055000

Power Supply Charges:

Component	
Base Power Supply (per kWh)	$0.048610
PPFAC (%) (see Rider-1 for current rate)	Varies

Small General Service Demand Time-of-Use (SGS-10 Demand TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rates, when all energy is supplied at one point of delivery and through one metered service.

This rate is optional for Small General Service Time-of-Use Customers, but mandatory for Small General Service Time-of-Use Customers taking service under Rider-10, Net Metering for Certain Partial Requirements Service (NM-PRS), Post June 1, 2015.

The supply of electric service under a residential rate to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the electricity used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters. Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises must be classified as non-residential and the appropriate general service rate will be applied.

Service under this rate will commence when the appropriate meter has been installed.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

In the event measured kW meets or exceeds 40 kW, the Customer will be moved to the Medium General Service Time-of-Use rate.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND, AND ENERGY CHARGES

Basic Service Charge:	$30.00 per month

Demand Charges (per kW)

	Delivery Services-Demand
0 - 15 kW	$6.85
Over 15 kW	$7.85

Energy Charges (per kWh)

Summer (May – October)	Delivery Services-Energy	Power Supply Charges[1]		Total[2]
		Base Power	PPFAC[1]	
0 – 7,500 kWh				
On-Peak	$0.011100	$0.126510	Varies	$0.137610
Off-Peak	$0.011100	$0.033010	Varies	$0.044110
Over 7,500 kWh				
On-Peak	$0.055000	$0.126510	Varies	$0.181510
Off-Peak	$0.055000	$0.033010	Varies	$0.088010

Winter (November – April)	Delivery Services-Energy	Power Supply Charges[1]		Total[2]
		Base Power	PPFAC[1]	
0 – 7,500 kWh				
On-Peak	$0.011100	$0.108510	Varies	$0.119610
Off-Peak	$0.011100	$0.032910	Varies	$0.044010
Over 7,500 kWh				
On-Peak	$0.055000	$0.108510	Varies	$0.163510
Off-Peak	$0.055000	$0.032910	Varies	$0.087910

1. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.
2. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

Calculation of Tiered (Block) Usage by TOU Period:

Step 1: Calculate percent usage by TOU period.
Step 2: Calculate the kWh usage by tier (block).
Step 3: Multiply percent usage by TOU period by kWh usage by tier to obtain tiered usage by TOU period.
Example: A Customer using 10,000 kWh in a month, with 20% on-peak usage and 80% off-peak usage will have 1,500 kWh in on-peak first tier, 500 kWh in on-peak second tier, 6,000 kWh in off-peak first tier and 2,000 kWh in off-peak second tier.

kWh	On-Peak	Off-Peak	Total
0 – 7,500 kWh	1,500	6,000	7,500
Over 7,500 kWh	500	2,000	2,500
Total	2,000	8,000	10,000

BILLING DEMAND

The monthly billing demand shall be the maximum 1-hour measured demand in the billing month.

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 5:00 a.m. - 9:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 1.18 per month
Meter Reading	$11.51 per month
Billing & Collection	$ 5.17 per month
Customer Delivery	$12.14 per month
Total	$30.00 per month

Demand Charge Components (per kW) (Unbundled):

Demand Delivery	
0 – 15 kW	$3.77
Over 15 kW	$4.77
Generation Capacity	$1.56
Transmission	$1.52

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	
0 – 7,500 kWh	$0.011100
Over 7,500 kWh	$0.055000

Power Supply Charges:

Component	
Base Power Supply Summer (May – October) On-Peak (per kWh)	$0.126510
Base Power Supply Summer (May – October) Off-Peak (per kWh)	$0.033010
Base Power Supply Winter (November – April) On-Peak (per kWh)	$0.108510
Base Power Supply Winter (November – April) Off-Peak (per kWh)	$0.032910
PPFAC (%) (see Rider-1 for current rate)	Varies

Medium General Service (MGS)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service.

In the event measured kW meets or exceeds 750 kW the Customer will be moved to the Large General Service rate.

Not applicable to resale, breakdown, temporary, standby or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND AND ENERGY CHARGES

Basic Service Charge: $100.00 per month

Demand Charge: $13.05 per kW

Energy Charge (per kWh):

	Delivery Services-Energy	Power Supply Charges[1]		Total[2]
		Base Power	PPFAC[1]	
All kWh	$0.005500	$0.048440	Varies	$0.053940

1. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.
2. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

BILLING DEMAND
The monthly billing demand shall be the the greater of the following:

1. The greatest measured 15 minute interval demand read of the meter during all hours of the billing period;
2. 75% of the greatest demand used for billing purposes in the preceding 11 months; or
3. The contract capacity or 20 kW, whichever is greater.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a Customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 210-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 1.67 per month
Meter Reading	$ 10.44 per month
Billing & Collection	$ 7.38 per month
Customer Delivery	$ 80.51 per month
Total	$100.00 per month

Demand Charges (per kW) (Unbundled):

Component	
Demand Delivery	$ 8.38
Generation Capacity	$ 2.37
Transmission	$ 2.30

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	$0.005500

Power Supply Charges:

Component	
Base Power Supply (per kWh)	$0.048440
PPFAC (%) (see Rider-1 for current rate)	Varies

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 211
Superseding:

Medium General Service Time-of-Use (MGS TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service.

In the event measured kW meets or exceeds 750 kW the Customer will be moved to the Large General Service Time-of-Use rate.

Not applicable to resale, breakdown, temporary, standby or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND AND ENERGY CHARGES

Basic Service Charge: $100.00 per month

Demand Charge: $13.05 per kW

Energy Charges (per kWh):

Summer (May – October)	Delivery Services-Energy	Power Supply Charges[1]		Total[2]
		Base Power	PPFAC[1]	
On-Peak	$0.005500	$0.109900	Varies	$0.115400
Off-Peak	$0.005500	$0.033500	Varies	$0.039000

Winter (November – April)	Delivery Services-Energy	Power Supply Charges[1]		Total[2]
		Base Power	PPFAC[1]	
On-Peak	$0.005500	$0.089900	Varies	$0.095400
Off-Peak	$0.005500	$0.031600	Varies	$0.037100

1. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.
2. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

BILLING DEMAND

The monthly billing demand shall be the the greater of the following:

1. The greatest measured 15 minute interval demand read of the meter during all hours of the billing period;
2. 75% of the greatest demand used for billing purposes in the preceding 11 months; or
3. The contract capacity or 20 kW, whichever is greater.

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 5:00 a.m. - 9:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the Customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 1.67 per month
Meter Reading	$ 10.44 per month
Billing & Collection	$ 7.38 per month
Customer Delivery	$ 80.51 per month
Total	$100.00 per month

Demand Charge (per kW) (Unbundled):

Component	
Demand Delivery	$ 8.38
Generation Capacity	$ 2.37
Transmission	$ 2.30

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	$0.005500

Power Supply Charges:

Component	
Base Power Supply Summer (May – October) On-Peak (per kWh)	$0.109900
Base Power Supply Summer (May – October) Off-Peak (per kWh)	$0.033500
Base Power Supply Winter (November – April) On-Peak (per kWh)	$0.089900
Base Power Supply Winter (November – April) Off-Peak (per kWh)	$0.031600
PPFAC (%) (see Rider -1 for current rate)	Varies

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 212
Superseding:

Time-of-Use for Medium General Service Schools (MGS-TOU-S)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all private and public schools (K-12) unless otherwise addressed by specific rates, when all energy is supplied at one point of delivery and through one metered service.

In the event measured kW meets or exceeds 750 kW the Customer will be moved to the Large General Service Schools TOU-S rate.

Service under this rate will commence when the appropriate meter has been installed.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND AND ENERGY CHARGES

Basic Service Charge: $100.00 per month

Demand Charge: $13.05 per kW

Energy Charges (per kWh):

Summer (May – October)	Delivery Services-Energy	Power Supply Charges[1]		Total[2]
		Base Power	PPFAC[1]	
On-Peak	$0.005500	$0.115600	Varies	$0.121100
Off-Peak	$0.005500	$0.039200	Varies	$0.044700

Winter (November – April)	Delivery Services-Energy	Power Supply Charges[1]		Total[2]
		Base Power	PPFAC[1]	
On-Peak	$0.005500	$0.095600	Varies	$0.101100
Off-Peak	$0.005500	$0.037300	Varies	$0.042800

1. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.
2. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month

BILLING DEMAND

The monthly billing demand shall be the the greater of the following:

1. The greatest measured 15 minute interval demand read of the meter during all hours of the billing period;
2. 75% of the greatest demand used for billing purposes in the preceding 11 months; or
3. The contract capacity or 20 kW, whichever is greater.

TIME-OF-USE PERIODS

The Summer On-Peak period is 3:00 p.m. to 7:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 5:00 a.m. - 9:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 1.67 per month
Meter Reading	$ 10.44 per month
Billing & Collection	$ 7.38 per month
Customer Delivery	$ 80.51 per month
Total	$100.00 per month

Demand Charge (per kW) (Unbundled):

Component	
Demand Delivery	$ 8.38
Generation Capacity	$ 2.37
Transmission	$ 2.30

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	$0.005500

Power Supply Charges:

Component	
Base Power Supply Summer (May – October) On-Peak (per kWh)	$0.115600
Base Power Supply Summer (May – October) Off-Peak (per kWh)	$0.039200
Base Power Supply Winter (November – April) On-Peak (per kWh)	$0.095600
Base Power Supply Winter (November – April) Off-Peak (per kWh)	$0.037300
PPFAC (%) (see Rider -1 for current rate)	Varies

Large General Service (LGS)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, temporary, standby or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at a voltage of less than 69 kV and subject to availability at point of delivery.

Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND AND ENERGY CHARGES

Basic Service Charge: $300.00 per month

Demand Charge: $12.96 per kW

Energy Charge (per kWh):

	Delivery Services-Energy	Power Supply Charges[1]		Total[2]
		Base Power	PPFAC[1]	
All kWh	$0.005400	$0.048400	Varies	$0.053800

1. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.
2. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

BILLING DEMAND
The monthly billing demand shall be the greater of the following:

1. The greatest measured 15 minute interval demand read of the meter during all hours of the billing period;
2. 75% of the greatest demand used for billing purposes in the preceding 11 months; or
3. The contract capacity or 450 kW, whichever is greater.

The Company reserves the right to require a Customer to install equipment to maintain an acceptable power factor at the Customer's expense.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 220-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Basic Service Charge Components (Unbundled):

Description	Basic Service Charge
Meter Services	$ 5.01 per month
Meter Reading	$ 31.32 per month
Billing & Collection	$ 22.15 per month
Customer Delivery	$241.52 per month
Total	$300.00 per month

Demand Charges (per kW) (Unbundled):

Component	Rate
Demand Delivery	$ 8.29
Generation Capacity	$ 2.37
Transmission	$ 2.30

Energy Charge Components (per kWh) (Unbundled):

	Rate
Local Delivery	$0.005400

Power Supply Charges:

Component	Rate
Base Power Supply (per kWh)	$0.048400
PPFAC (%) (see Rider-1 for current rate)	Varies

Large General Service Time-of-Use (LGS TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service.

Service under this rate will commence when the appropriate meter has been installed.

Not applicable to resale, breakdown, temporary, standby or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at a voltage of less than 69 kV and subject to availability at point of delivery.

Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND AND ENERGY CHARGES

Basic Service Charge: $300.00 per month

Demand Charge: $12.96 per kW

Energy Charges (per kWh):

Summer (May – October)	Delivery Services-Energy	Power Supply Charges[1]		Total[2]
		Base Power	PPFAC[1]	
On-Peak	$0.005400	$0.145510	Varies	$0.150910
Off-Peak	$0.005400	$0.034510	Varies	$0.039910

Winter (November – April)	Delivery Services-Energy	Power Supply Charges[1]		Total[2]
		Base Power	PPFAC[1]	
On-Peak	$0.005400	$0.124510	Varies	$0.129910
Off-Peak	$0.005400	$0.032910	Varies	$0.038310

1. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.
2. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

BILLING DEMAND

The monthly billing demand shall be the greater of the following:

1. The greatest measured 15 minute interval demand read of the meter during all hours of the billing period;
2. 75% of the greatest demand used for billing purposes in the preceding 11 months; or
3. The contract capacity or 450 kW, whichever is greater.

The Company reserves the right to require a Customer to install equipment to maintain an acceptable power factor at the Customer's expense.

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 5:00 a.m. - 9:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 5.01 per month
Meter Reading	$ 31.32 per month
Billing & Collection	$ 22.15 per month
Customer Delivery	$241.52 per month
Total	$300.00 per month

Demand Charge (per kW) (Unbundled):

Component	
Demand Delivery	$ 8.29
Generation Capacity	$ 2.37
Transmission	$ 2.30

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	$0.005400

Power Supply Charges:

Component	
Base Power Supply Summer (May – October) On-Peak (per kWh)	$0.145510
Base Power Supply Summer (May – October) Off-Peak (per kWh)	$0.034510
Base Power Supply Winter (November – April) On-Peak (per kWh)	$0.124510
Base Power Supply Winter (November – April) Off-Peak (per kWh)	$0.032910
PPFAC (%) (see Rider -1 for current rate)	Varies

UniSource Energy SERVICES

UNS Electric, Inc.

Original Sheet No.: 222
Superseding:

Time-of-Use for Large General Service Schools (LGS-TOU-S)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all private and public schools (K-12) unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service.

Service under this rate will commence when the appropriate meter has been installed.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at a voltage of less than 69 kV and subject to availability at point of delivery.

Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND AND ENERGY CHARGES

Basic Service Charge: $300.00 per month

Demand Charge: $12.96 per kW

Energy Charges (per kWh):

Summer (May – October)	Delivery Services-Energy	Power Supply Charges[1]		Total[2]
		Base Power	PPFAC[1]	
On-Peak	$0.005400	$0.150210	Varies	$0.155610
Off-Peak	$0.005400	$0.039210	Varies	$0.044610

Winter (November – April)	Delivery Services-Energy	Power Supply Charges[1]		Total[2]
		Base Power	PPFAC[1]	
On-Peak	$0.005400	$0.129210	Varies	$0.134610
Off-Peak	$0.005400	$0.037610	Varies	$0.043010

1. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.
2. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month

BILLING DEMAND

The monthly billing demand shall be the greater of the following:

1. The greatest measured 15 minute interval demand read of the meter during all hours of the billing period;
2. 75% of the greatest demand used for billing purposes in the preceding 11 months; or
3. The contract capacity or 450 kW, whichever is greater.

The Company reserves the right to require a Customer to install equipment to maintain an acceptable power factor at the Customer's expense.

TIME-OF-USE PERIODS

The Summer On-Peak period is 3:00 p.m. to 7:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 5:00 a.m. - 9:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 5.01 per month
Meter Reading	$ 31.32 per month
Billing & Collection	$ 22.15 per month
Customer Delivery	$241.52 per month
Total	$300.00 per month

Demand Charge (per kW) (Unbundled):

Component	
Demand Delivery	$8.29
Generation Capacity	$2.37
Transmission	$2.30

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	$0.005400

Power Supply Charges:

Component	
Base Power Supply Summer (May – October) On-Peak (per kWh)	$0.150210
Base Power Supply Summer (May – October) Off-Peak (per kWh)	$0.039210
Base Power Supply Winter (November – April) On-Peak (per kWh)	$0.129210
Base Power Supply Winter (November – April) Off-Peak (per kWh)	$0.037610
PPFAC (%) (see Rider -1 for current rate)	Varies

Large Power Service (LPS)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, temporary, standby or auxiliary service.

CHARACTER OF SERVICE
The service shall be three-phase, 60 Hertz, and at the Company's standard transmission voltages that are available within the vicinity of the Customer's premises.

Primary metering at primary voltages greater than or equal to 69 kV shall be required for service under this tariff.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND AND ENERGY CHARGES

Basic Service Charge: $1,200.00 per month

Demand Charge: $12.48 per kW

Energy Charge (per kWh):

	Delivery Services-Energy	Power Supply Charges[1]		Total[2]
		Base Power	PPFAC[1]	
All kWh	$0.000520	$0.048410	Varies	$0.048930

1. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.
2. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

BILLING DEMAND
The monthly billing demand shall be the greater of the following:

1. The greatest measured 15 minute interval demand read of the meter during all hours of the billing period;
2. The greatest demand metered in the preceding eleven (11) months; or
3. The contract capacity or 500 kW, whichever is greater.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than ninety-five percent (95%), an adjustment shall be applied to the bill as follows:

POWER FACTOR ADJUSTMENT
(Maximum Demand / (.05 + PF)) - Maximum Demand) x Demand Charge Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

POWER FACTOR
1. The Company may require the Customer by written notice to either maintain a specified minimum lagging power factor or the Company may after thirty (30) days install power factor corrective equipment and bill the Customer for the total costs of this equipment and installation.
2. In the case of apparatus and devices having low power factor, now in service, which may hereafter be replaced, and all similar equipment hereafter installed or replaced, served under general commercial schedules, the Company may require the Customer to provide, at the Customer's own expense, power factor corrective equipment to increase the power factor of any such devices to not less than ninety (90) percent.
3. If the Customer installs and owns the capacitors needed to supply his reactive power requirements, then the Customer must equip them with suitable disconnecting switches, so installed that the capacitors will be disconnected from the Company's lines whenever the Customer's load is disconnected from the Company's facilities.
4. Gaseous tube installations totaling more than one thousand (1,000) volt-amperes must be equipped with capacitors of sufficient rating to maintain a minimum of ninety percent (90%) lagging power factor.
5. Company installation and removal of metering equipment to measure power factor will be at the discretion of the Company.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the Customer or pursuant to the Customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

OTHER PROVISIONS
Service hereunder shall remain in full force and in effect until terminated by the Customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the Customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 101.86 per month
Meter Reading	$ 145.57 per month
Billing & Collection	$ 451.63 per month
Customer Delivery	$ 500.94 per month
Total	$1,200.00 per month

Demand Charge (per kW) (Unbundled):

Component	
Delivery Services- All kW	
Local Delivery	$5.22
Generation Capacity	$3.68
Transmission	$3.58

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	$0.000520

Power Supply Charges:

Component	
Base Power Supply (per kWh)	$0.048410
PPFAC (%) (see Rider-1 for current rate)	Varies

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 302
Superseding:

Large Power Service Time-of-Use (LPS-TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, temporary, standby or auxiliary service.

CHARACTER OF SERVICE
The service shall be three-phase, 60 Hertz, and at the Company's standard transmission voltages that are available within the vicinity of the Customer's premises.

Primary metering at primary voltages greater than or equal to 69kV shall be required for service under this tariff.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND AND ENERGY CHARGES

Basic Service Charge: $1,200.00 per month

Demand Charge $12.48 per kW

Energy Charges (per kWh):

Summer (May – October)	Delivery Services-Energy	Power Supply Charges[1] Base Power	PPFAC[1]	Total[2]
On-Peak	$0.000520	$0.122510	Varies	$0.123030
Off-Peak	$0.000520	$0.032110	Varies	$0.032630

Winter (November – April)	Delivery Services-Energy	Power Supply Charges[1] Base Power	PPFAC[1]	Total[2]
On-Peak	$0.000520	$0.092110	Varies	$0.092630
Off-Peak	$0.000520	$0.030910	Varies	$0.031430

1. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.
2. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

BILLING DEMAND
The monthly billing demand shall be the greater of the following:

1. The greatest measured 15 minute interval demand read of the meter during the on-peak hours of the billing period;
2. One-half of the greatest measured 15 minute interval demand read of the meter during the off-peak hours of the billing period;
3. The greater of (1) or (2) above during the preceding 11 months; or
4. The contract capacity or 500 kW, whichever is greater.

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 12:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than ninety-five percent (95%), an adjustment shall be applied to the bill as follows:

POWER FACTOR ADJUSTMENT
(Maximum Demand / (.05 + PF)) - Maximum Demand) x Demand Charge Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

POWER FACTOR
1. The Company may require the Customer by written notice to either maintain a specified minimum lagging power factor or the Company may after thirty (30) days install power factor corrective equipment and bill the Customer for the total costs of this equipment and installation.

2. In the case of apparatus and devices having low power factor, now in service, which may hereafter be replaced, and all similar equipment hereafter installed or replaced, served under general commercial schedules, the Company may require the Customer to provide, at the Customer's own expense, power factor corrective equipment to increase the power factor of any such devices to not less than ninety (90) percent.
3. If the Customer installs and owns the capacitors needed to supply his reactive power requirements, then the Customer must equip them with suitable disconnecting switches, so installed that the capacitors will be disconnected from the Company's lines whenever the Customer's load is disconnected from the Company's facilities.
4. Gaseous tube installations totaling more than one thousand (1,000) volt-amperes must be equipped with capacitors of sufficient rating to maintain a minimum of ninety percent (90%) lagging power factor.
5. Company installation and removal of metering equipment to measure power factor will be at the discretion of the Company.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the Customer or pursuant to the Customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

OTHER PROVISIONS
Service hereunder shall remain in full force and in effect until terminated by the Customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the Customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 101.86 per month
Meter Reading	$ 145.57 per month
Billing & Collection	$ 451.63 per month
Customer Delivery	$ 500.94 per month
Total	$1,200.00 per month

Demand Charge (per kW) (Unbundled):

Component	
Delivery Services- All kW	
Local Delivery	$5.22
Generation Capacity	$3.68
Transmission	$3.58

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	$0.000520

Power Supply Charges:

Component	
Base Power Supply Summer (May – October) On-Peak (per kWh)	$0.122510
Base Power Supply Summer (May – October) Off-Peak (per kWh)	$0.032110
Base Power Supply Winter (November – April) On-Peak (per kWh)	$0.092110
Base Power Supply Winter (November – April) Off-Peak (per kWh)	$0.030910
PPFAC (%) (see Rider -1 for current rate)	Varies

Lighting Service (LTG)

AVAILABILITY
At any point where the Company in its judgment has facilities of adequate capacity and suitable voltage available.

APPLICABILITY
Applicable to any Customer for private and public street lighting or outdoor area lighting where this service can be supplied from existing facilities of the Company. The Company will install, own, operate, and maintain the complete lighting installation including lamp and globe replacements. Not applicable to resale service.

To any Customer, including public agencies, for the lighting of streets, alleys, thoroughfares, public parks, playgrounds, or other public or private property where such lighting is controlled by a photocell and a contract for service is entered into with the Company.

CHARACTER OF SERVICE
Service is supplied on Company-owned fixtures and poles which are maintained by the Company. The poles, fixtures, and lamps available are the standard items stocked by the Company, and service is rendered at standard available voltages. Multiple or series street lighting systems may be installed at the option of the Company and at one standard nominal voltage.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

The monthly bill shall be the sum of the following charges and adjustments for each light:

Service Charge (per month):	Overhead Service	Underground Service
Existing Wood Pole	$ 2.35	$ 2.35
New 30' Wood Pole (Class 6)	$ 4.68	$ 7.04
New 30' Metal or Fiberglass	$ 9.35	$11.67

Lighting Charge:
Based on the rated wattage value of each lamp installed per month: $0.060516 per watt

Base Power Supply Charge: based on the rated wattage value of each lamp installed per month: $0.013110 per kWh

The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rate Rider-1 for current rate.

CONTRACT PERIOD
All lighting installations will require a contract for service as follows:

Three (3) years initial term for installations on existing facilities.

TERMS AND CONDITIONS

1. For each light, overhead extensions beyond one hundred fifty (150) feet and underground extensions beyond one hundred (100) feet will require specific agreements providing adequate revenue or arrangements for construction financing.
2. The Customer is not authorized to make connections to the lighting circuit or make attachments or alterations to the Company-owned pole.
3. Should a Customer request a relocation of a dusk-to-dawn lighting installation, the costs of such relocation must be borne by the Customer.
4. The Customer is expected to notify the Company when lamp outages occur.
5. The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.
6. The Company will require a non-refundable contribution for the installation of new construction for facilities of $150.00.
7. A late payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.
8. When a residential Customer's privately owned underground service cable has failed, the Customer has two (2) options. The Customer can have their cable repaired by a private electrical contractor which must comply with local governmental codes and ordinances or the Customer can bring their service entrance up to current Company standards. The Customer will be required to provide a service trench, conduit, conduit installation, backfill, landscape restoration and paving. The Company will furnish, install, own and maintain the underground single-phase cables to Customer's Company-approved Point of Delivery.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

New 30' Wood Pole (Class 6) - Overhead	
Billing and Collections	$2.57 per unit
Customer Delivery	$2.11 per unit
New 30' Metal or Fiberglass - Overhead	
Billing and Collections	$5.14 per unit
Customer Delivery	$4.21 per unit
Existing Wood Pole – Underground	
Billing and Collections	$1.29 per unit
Customer Delivery	$1.06 per unit
New 30' Wood Pole Class 6 – Underground	
Billing and Collections	$3.87 per unit
Customer Delivery	$3.17 per unit
New 30' Metal or Fiberglass – Underground	
Billing and Collections	$6.42 per unit
Customer Delivery	$5.25 per unit
Lighting Charge	
Local Delivery	$0.054106 per watt
Generation Capacity	$0.003250 per watt
Transmission	$0.003160 per watt

Interruptible Power Service (IPS-F)

AVAILABILITY
New Customers, including current Customers who relocate, are not eligible for service under this rate.

TRANSITION PERIOD
Customers taking service under this rate prior to January 1, 2014 will be given twenty-four (24) months from January 1, 2014 to furnish, install, own, and maintain at each point of delivery all necessary Company approved equipment which will enable the Company to interrupt service with its master control station. After December 31, 2015, if the Customer has not installed this equipment, they will be placed on the otherwise applicable firm rate.

APPLICABILITY
This service is normally provided at one point of delivery measured through one meter. More than one service and meter may be provided in instances where such is permitted under 230.2 (A) through (D) of the National Electric Code with prior approval of the UNS Electric Engineering Department.

To any Customer with a minimum demand of 50 kW and is interruptible within fifteen (15) minutes of notice by the Company. The Customer must be able to interrupt service for up to eight (8) hours per day.

Not applicable to resale, breakdown, temporary, standby or auxiliary service.

CHARACTER OF SERVICE
Service shall be three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND AND ENERGY CHARGES:

Basic Service Charge: $75.00 per month

Demand Charge: $6.52 per kW

Energy Charge (per kWh):

	Delivery Services-Energy	Power Supply Charges[1]		Total[2]
		Base Power	PPFAC[1]	
All kWh	$0.019790	$0.049821	Varies	$0.069611

1. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.
2. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

PENALTY FOR FAILURE TO INTERRUPT:
In the event that the Customer fails to interrupt its load when requested to do so by the Company, the Customer shall pay an additional charge as follows:

Billing Demand Charge per kW @ $25.00
Unbundled $/kWh Charge is entirely a Delivery Charge

For a second failure to interrupt in any twelve (12) month period, the Customer will revert to the otherwise applicable firm Rate for a period of at least twelve (12) months.

DETERMINATION OF BILLING DEMAND
The monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month. If demand is not metered, the billing demand shall be based on nameplate ratings of connected motors and equipment, or by a test as approved by the Company.

TERMS AND CONDITIONS
A late payment charge as stated in the Company's Rules and Regulations will be applied to account balances carried forward from prior billings.

The Company reserves the right to interrupt service to the Customer at any time.

Customers who qualify for service under this Rate must remain on the Rate for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach. Service hereunder shall require the Customer to enter into a Service Agreement with the Company for a term of one (1) year or longer, with a minimum Contract Demand at the Company's option in view of the anticipated demand of the Customer.

The Company will endeavor to provide the Customer with as much advance notice as possible of the required interruptions. However, the Customer shall interrupt service within fifteen (15) minutes.

The Company reserves the right to have automatic equipment installed for immediate interruption of the Customer's load. Should the Company's automatic equipment fail to interrupt the load, no penalty will be assessed.

The Company shall not be responsible for any loss or damage caused by or resulting from interruption of service under this Rate.

Standby, supplemental or breakdown service shall not be rendered under this Rate.
Service under this Rate is for the exclusive use of the Customer and shall not be resold or shared with others, unless authorized by the Company.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Commission shall apply where not inconsistent with this rate.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 1.25 per month
Meter Reading	$ 7.83 per month
Billing & Collection	$ 5.54 per month
Customer Delivery	$60.38 per month
Total	$75.00 per month

Demand Charge (per kW) (Unbundled):

Local Delivery	$1.85
Generation Capacity	$2.37
Transmission	$2.30

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	$0.019790

Power Supply Charges:

Component	
Base Power Supply (per kWh)	$0.049821
PPFAC (%) (see Rider-1 for current rate)	Varies

Rider R-1
Purchased Power and Fuel Adjustment Clause (PPFAC)

APPLICABILITY

The Purchased Power and Fuel Adjustment Clause (PPFAC) will be applied to all Customers taking service from the Company pursuant to the Arizona Corporation Commission (ACC) Decision No. 70360 (May 27, 2008) and as updated and defined in the Company's PPFAC Plan of Administration approved in ACC Decision No. XXXXX.

RATE

The Customer's monthly bill shall consist of applicable rate charges and adjustments in addition to the PPFAC. The percentage-based PPFAC adjustment, as shown below which reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. The percentage-based PPFAC adjustment will apply to the Customer's Base Power Charge.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

This standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 701-1
Superseding :

Purchased Power Fuel Adjustment Clause
RIDER R-1

APPLICABILITY: To all Company Rates, unless otherwise specified.
Redesign table due to the purposed changes for the percentage PPFAC

Issued: ____________
Month Day Year

Effective: ____________
Month Day Year

Filed By:	Kentton C. Grant	Rate:	R-1
Title:	Vice President	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	Pending

Rider R-2
Demand Side Management Surcharge (DSMS)

APPLICABILITY

The Demand Side Management Surcharge (DSMS) will be applied to all Customers taking service from the Company as mandated by the Arizona Corporation Commission (ACC), unless otherwise specified.

RATES

The DSMS shall be applied to all monthly bills. The DSMS will be assessed on a per kWh basis. The rates are shown in the UNS Electric Statement of Charges.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the ACC see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company, and/or the price of, or revenue from, electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the ACC shall apply where not inconsistent with this rider.

Rider-3
Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS-F

AVAILABILITY
The Market Cost of Comparable Conventional Generation (MCCCG) calculation, Rider-3, is restricted solely to Rider-4, Net Metering for Certain Partial Requirements Service (NM-PRS-F). If for a billing month a Rider-4 NM-PRS-F Customer's generation facility's energy production exceeds the energy supplied by the Company, the Customer's bill for the next billing period shall be credited for the excess generation as described in Rider-4 NM-PRS-F. The excess kWh during the billing period shall be used to reduce the kWh supplied (not kW or kVA demand or customer/facilities charges) and billed by the Company during the following billing period. Each calendar year, for the customer bills produced in October (September usage) or a customer's "Final" bill - the Company shall credit the Customer for the positive balance of excess kWhs (if any) after netting against billing period usage. The payment for the purchase of the excess kWhs will be at the Company's applicable avoided cost, which for purposes of Rider-4 NM-PRS-F shall be the simple average of the hourly MCCCG as described below for the applicable year.

The Arizona Corporation Commission (ACC) provided guidance on defining MCCCG in the context of its REST Rules and identified the MCCCG as "the Affected Utility's energy and capacity cost of producing or procuring the incremental electricity that would be avoided by the resources used to meet the Annual Renewable Energy Requirement, taking into account hourly, seasonal and long term supply and demand circumstances. Avoided costs include any avoided transmission and distribution costs and any avoided environmental compliance costs." R14-2-1801.11.

CALCULATION/METHODOLOGY
For purposes of calculating credits to the Customer for Excess Generation, the unit price paid (Credit for Excess Generation) shall be the simple average of the MCCCG over the 8,760 hours (8,784 in a leap year) hours in the forecasted year. The MCCCG in each hour is based on whether native load requirements will be met by internally owned or contracted generation resources or if market purchases will be required to meet native load requirements. The following table provides a description of the MCCCG methodology. The hourly MCCCG cost determination criteria is based on the Market Condition and Dispatch Type. This method of cost determination is very data intensive and will be calculated annually by running UNS Electric's "Planning and Risk" modeling software, and the rate will be filed with the Commission by April 1 of each year.

RATE
The Customer monthly bill shall consist of the applicable rate charges and adjustments in addition to the Credit for Excess Generation based on the MCCCG. The MCCCG rate is an amount expressed as a rate per kWh charge that is approved by the ACC on or before June 1 of each year and effective with the first billing cycle in June, as shown in the UNS Electric Statement of Charges.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the ACC see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

MCCCG Cost Determination Matrix

Market Condition and Dispatch Type	Selling to Market from In House Real and Contracted Generation Sources	MCCCG Cost Based on Incremental Production/Purchase Cost of Base Load Generation for that hour			
	No Market Transactions from/to In House and Contracted Generation Sources				
	Purchasing from Day Ahead Market, but not Spot Market, to meet Native Load Requirements	MCCCG Cost Based on Average Day Ahead Market Price of Purchased Power for that hour			
	Purchasing from Spot Market to meet Native Load Requirements	MCCCG Cost Based on Average Spot Market Price of Purchased Power for that hour			

Incremental Production / Purchase of Base Load - The cost of the next kWh (incremental) amount of load that has to be provided by UNS Electric generation sources and/or purchased power. This will be dependent on the season, month and time of day.

If Day Ahead Market or Spot Market purchases are being used to provide for reliability support capacity to meet native load requirements by freeing up in house or contracted generation resources for regulation or spinning reserve purposes for support of native load requirements, that would still represent a Market Purchase for purposes of determining which matrix box is applicable.

Rider-4
Net Metering for Certain Partial Requirements Service (NM-PRS-F)

AVAILABILITY
Available throughout the Company's entire electric service area to any Customer with a facility for the production of electricity on its premises using Renewable Resources[1], a Fuel Cell [2] or Combined Heat and Power (CHP)[3] to generate electricity, which is operated by or on behalf of the Customer, is intended to provide all or part of the Customer's electricity requirements, has a generating capacity less than or equal to 125% of the Customer's total connected load at the metered premise, or in the absence of load data, has capacity less than the Customer's electric service drop capacity, and is interconnected with and can operate in parallel and in phase with the Company's existing distribution system. Customer shall comply with all applicable federal, state, and local laws, regulations, ordinances and codes governing the production and/or sale of electricity.

For purposes of this rate, the following notes and/or definitions apply:

[1] Renewable Resources means natural resources that can be replenished by natural process. Renewable Resources include biogas, biomass, geothermal, hydroelectric, solar, or wind.

[2] Fuel Cell means a device that converts the chemical energy of a fuel directly into electricity without intermediate combustion or thermal cycles. The source of the chemical reaction must be derived from Renewable Resources.

[3] Combined Heat and Power (CHP) also known as cogeneration means a system that generates electricity and useful thermal energy in a single integrated system such that the useful power output of the facility plus one-half the useful thermal energy output during any 12-month period must be no less than 42.5 percent of the total energy input of fuel to the facility.

CHARACTER OF SERVICE
The service shall be single- or three-phase, 60 Hertz, at one standard nominal voltage as mutually agreed and subject to availability at the point of delivery. Primary metering will be used by mutual agreement between the Company and the Customer.

RATE
Basic Service Charges shall be billed pursuant to the Customer's standard offer rate otherwise applicable under full requirements of service.

Power sales and special services supplied by the Company to the Customer in order to meet the Customer's supplemental or interruptible electric requirements will be priced pursuant to the Customer's standard offer rate otherwise applicable under full requirements service.

Non-Time-of-Use Rates: For Customers taking service under a Standard Retail Rate that is not a Time-of-Use rate, the Customer Supplied kWh shall be credited against the Company Supplied kWh. The Customer's monthly bill shall be based on this net kWh amount. Any monthly Excess Generation will be treated in accordance with the provisions outlined below.

Time-of-Use Rates: For Customers taking service under a Standard Retail Rate that is a Time-of-Use rate, the Customer Supplied kWh during on-peak hours shall be credited against the Company Supplied kWh during on-peak hours. All Customer Supplied kWh during off-peak hours shall be credited against the Company Supplied kWh during off-peak hours. The Customer's monthly bill shall be based on this net kWh amount. Any monthly Excess Generation will be treated in accordance with the provisions outlined below.

EXCESS GENERATION

If for a billing month the Customer's generation facility's energy production exceeds the energy supplied by the Company, the Customer's bill for the next billing period shall be credited for the excess generation. That is, the excess kWh during the billing period shall be used to reduce the kWh supplied (not kW or kVA demand or customer/facilities charges) and billed by the Company during the following billing period. Customers taking service under a time-of-use rate who are to receive credit in a subsequent billing period for excess kWh generated shall receive such credit in the next billing period for the on-peak, or off-peak periods in which the kWh were generated by the Customer. Time-of-Use Customer's taking service in the billing month of April shall receive a credit to summer on-peak and summer off-peak usage in the billing month of May for any winter on-peak and/or winter off-peak excess generation for April.

Each calendar year, for the customer bills produced in October (September usage) or a customer's "Final" bill - the Company shall credit the Customer for the balance of excess kWhs after netting. The payment for the purchase of the excess kWhs will be at the Company's applicable avoided cost, which for purposes of this rate shall be the simple average of the hourly Market Cost of Comparable Conventional Generation (MCCCG) Rider-3 for the applicable year. The MCCCG, as it applies to this rate, is specified in Rider-3 MCCCG - Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS-F (Net Metering for Certain Partial Requirements Service).

METERING

The Company will install a bi-directional meter at the point of delivery to the customer and meter at the point of output from each of the Customer's generators. At the Company's request a dedicated phone line will be provided by the customer to the metering to allow remote interegation of the meters at each site. If by mutal agreement between company and customer that a phone line is impractical or can not be provided - the customer will work with company to allow for the installation of equipment, on or with customer facilities or equipment to allow remote acces to each meter. Any additional cost of communication, such as but not limited too, cell phone service fees will be the responsibility of the customer.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

Rider-5
Electric Service Solar Rider
(Bright Arizona Community Solar™)

APPLICABILITY
Rider-5 is for individually metered Customers who wish to participate in the Bright Arizona Community Solar Program. Under Rider-5, Customers will be able to purchase blocks of electricity from solar generation sources. Participation in Rider-5 is limited in the Company's sole discretion to the amount of solar generation available and subscription will be made on a first come, first served basis. In order to maximize subscription under Rider-5, the Company may limit the amount of solar block energy purchased by individual Customers. Rider-5 is further restricted to Customers being served under one of the following rates:

1. Residential Service Rate, RES-01 (RES-01 TOU is not applicable)
2. Small General Service Rate, SGS-10 (SGS-10 TOU is not applicable)
3. Medium General Service Rate, MGS (MGS-TOU is not applicable)

Customers being served under self-generation riders or plans may not purchase power under Rider-5 (including, but not limited to Rider-4 Net Metering for Certain Partial Requirements Service (NM-PRS-F) and Rider-10 Net Metering for Certain Partial Requirements Service (NM-PRS), Post June 1, 2015.

RATE
Customers can contract for a portion or up to their average annual usage in solar blocks of 150 kilowatt hours (kWh) each. Transmission and distribution charges will be applied to all energy delivered, including energy delivered under Rider-5. The Customer is responsible for paying (each month) all charges incurred under their applicable rate, and the total solar energy contracted for multiplied by the applicable solar block energy rate. Any demand based charges under the Customer's current rate will not be affected by elections under Rider-5. No discounts specified in any of the above-listed standard offer tariffs will apply to this rider. The rates are shown in the UNS Electric Statement of Charges.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

TAX CLAUSE
To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

TERMS AND CONDITIONS

1. Customers may contract for a portion or up to their average annual usage in solar blocks of 150 kWh. If Customer's annual average usage is not available, UNS Electric will apply the appropriate class average. This limit can be reviewed annually at the request of the Customer.

2. Each solar block's energy rate will be maintained for twenty years from the date of purchase. For the purposes of the twenty year energy rate, solar blocks will be attributed to the Customer's original service address. Transfer of service under Rider-5 is prohibited. Should the Customer cancel service for any reason, his or her subscription under Rider-5 will expire.

3. Customers may add or delete solar blocks once within a twelve month period. Any addition of solar blocks will be at the then offered solar block energy rate.

4. Solar blocks will be applied to the actual energy usage each month. Electricity used in excess of the purchased solar blocks will be billed at the Customer's regular energy rate. If electricity usage is below the amount covered by the solar block(s), then the excess kWhs will be rolled forward and credited again the Customer's usage in the following month. The Customer will still be responsible for the full cost of the block(s) each month.

5. Customers will be credited for the balance of any excess kWhs annually, or on their final bill should the Customer terminate service under Rider-5. Each year, for the bills produced in October (September usage), UNS Electric will credit Customers their excess kWhs after netting and reset their balance to zero. Credit for excess kWhs will be at the energy rate of the oldest solar block.

6. All contracted solar block kWhs and associated charges in a billing month will be excluded from the calculation of PPFAC and REST charges and/or credits.

Rider-6
Renewable Energy Standard and Tariff (REST) Surcharge
REST-TS1 Renewable Energy Program Expense Recovery

APPLICABILITY
Mandatory, non-bypassable surcharge applied to all energy consumed by all Customers throughout Company's entire electric service area.

RATES
For all energy billed which is supplied by the Company to the Customer. The REST surcharge shall be applied to all monthly bills. The REST rates are shown in the UNS Electric Statement of Charges.

Note: An industrial Customer is one with monthly demand equal to or greater than 3,000 kW.

For non-metered services, the lesser of the load profile or otherwise estimated kWh required to provide the service in question, or the service's contract kWh shall be used in the calculation of the surcharge.

This charge will be a line item on Customer bills reading "Renewable Energy Standard Tariff."

Per Decision No. 73638, effective March 21, 2013, any Customer who has received incentives under the REST Rules, shall pay the average of the REST surcharge paid by members of their Customer class. This requirement shall apply to renewable systems reserved on and after January 1, 2012. Any Customer who has a renewable installation without incentives that is interconnected with UNS Electric's system shall pay the average of the REST surcharge paid by members of their Customer class. This requirement shall apply to renewable systems reserved on and after February 1, 2013. The average price is shown in the UNS Electric Statement of Charges.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

TAX CLAUSE
To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

Rider-7
Customer Self-Directed Renewable Energy Option
REST-TS2 Renewable Energy Standard Tariff

AVAILABILITY
Open to all Eligible Customers as defined at A.A.C. R14-02-1801.H.

APPLICABILITY
Any Eligible Customer that applies to the Company under this program and receives approval shall participate at its option.

PARTICIPATION PROCESS
An Eligible Customer seeking to participate shall submit to the Company a written application that describes the Distributed Renewable Energy (DRE) resources or facilities that it proposes to install and the estimated costs of the project. The Company shall have sixty (60) calendar days to evaluate and respond in writing to the Eligible Customer, either accepting or declining the project. If accepted, the Customer shall be reimbursed up to the actual dollar amounts of customer surcharge paid under the REST-TS1Tariff in any calendar year in which DRE facilities are installed as part of the accepted project. To qualify for such funds, the Customer shall provide at least half of the funding necessary to complete the project described in the accepted application, and shall provide the Company with sufficient and reasonable written documentation of the project's costs. Customer shall submit their application prior to May 1 of a given year to apply for funding in the following calendar year.

FACILITIES INSTALLED
The maintenance and repair of the facilities installed by a Customer under this program shall be the responsibility of the Customer following completion of the project. In order to be accepted by the Company for reimbursement purposes, the project shall, at a minimum, conform to the Company's System Qualification standards on file with the Commission. (REST Impolementation Plan, Renewable Energy Credit Purchase Program – RECPP, Distributed Generation Interconnection Requirements, Net Metering Tariff, Company's Interconnection Manual)

PAYMENTS AND CREDITS
All funds reimbursed by the Company to the Customer for installation of approved DRE facilities shall be paid on an annual basis no later than March 30th of each calendar year. All Renewable Energy Credits derived from a project, including generation and Extra Credit Multipliers, shall become the property of the Company and shall be applied towards the Company's Annual Renewable Energy Requirement as defined in A.A.C. R14-2-1801.B.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rider.

RELATED RIDER

- REST-TS1 - Renewable Energy Program Expense Recovery

Rider R-8
Lost Fixed Cost Recovery (LFCR)

APPLICABILITY
The Lost Fixed Cost Recovery (LFCR) will be applied to all Customers taking service from the Company other than lighting as defined in the Company's LFCR Plan of Administration (POA).

CHANGE IN RATE
The LFCR recovers a portion of the authorized margin approved in the Company's most recent rate case that has been lost as the result of implementing Arizona Corporation Commission (ACC)-mandated Energy Efficiency and Distributed Generation programs. Each year, a percentage-based rate will be placed in effect and charged to the participating rate classes for the 12-month period the LFCR adjustment is applicable. The total year-on-year adjustment cannot exceed 2% of the Company's most recent total combined retail calendar year revenues for all participating rate classes. The LFCR rate is shown in the UNS Electric Statement of Charges.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the ACC see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

Rider R-9
Transmission Cost Adjustor (TCA)

APPLICABILITY
The Transmission Cost Adjustor (TCA) will be applied to all Customers taking service from the Company as defined in the Company's TCA Plan of Administration (POA).

CHANGE IN RATE
The TCA recovers the change in transmission costs resulting from the Federal Energy Regulatory Commission (FERC) approved formula rate that is updated annually in accordance with the provisions of the Company's Open Access Transmission Tariff (OATT), available through the FERC eTariff website at: http://etariff.ferc.gov/TariffBrowser.aspx?tid=1697. The adjustment captures the difference between the level of transmission costs approved in the Company's last rate case and the amount calculated based on the FERC-approved formula rate. The adjustment can be a charge or a credit and will be updated annually as of the date set forth in the OATT.

> The TCA shall apply to all monthly bills either as a per kWh charge or as a per kW rate, depending on the Customer's effective service tariff, and is anticipated to become effective on the date the TCA is updated. The TCA rates are shown in the UNS Electric Statement of Charges.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
This standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

Rider-10
Net Metering for Certain
Partial Requirements Service (NM-PRS), Post June 1, 2015

AVAILABILITY

Available throughout the Company's entire electric service area to any Customer with a facility for the production of electricity on its premises using Renewable Resources[1], a Fuel Cell [2] or Combined Heat and Power (CHP)[3] to generate electricity, which is operated by or on behalf of the Customer, is intended to provide all or part of the Customer's electricity requirements, has a generating capacity less than or equal to 125% of the Customer's total connected load at the metered premise, or in the absence of load data, has capacity less than the Customer's electric service drop capacity, and is interconnected with and can operate in parallel and in phase with the Company's existing distribution system. Customer shall comply with all applicable federal, state, and local laws, regulations, ordinances and codes governing the production and/or sale of electricity.

For purposes of this Rate, the following notes and/or definitions apply:

[1] Renewable Resources means natural resources that can be replenished by natural process. Renewable Resources include biogas, biomass, geothermal, hydroelectric, solar, or wind.

[2] Fuel Cell means a device that converts the chemical energy of a fuel directly into electricity without intermediate combustion or thermal cycles. The source of the chemical reaction must be derived from Renewable Resources.

[3] Combined Heat and Power (CHP) also known as cogeneration means a system that generates electricity and useful thermal energy in a single integrated system such that the useful power output of the facility plus one-half the useful thermal energy output during any 12-month period must be no less than 42.5 percent of the total energy input of fuel to the facility.

CHARACTER OF SERVICE

The service shall be single- or three-phase, 60 Hertz, at one standard nominal voltage as mutually agreed and subject to availability at the point of delivery. Primary metering will be used by mutual agreement between the Company and the Customer.

RATE

Residential or Small General Service Customers taking service under this rider must take service in accordance with the "Demand" option of the applicable standard offer rate.

Basic Service Charges shall be billed pursuant to the Customer's standard offer rate otherwise applicable under full requirements service.

All power sales defined as "kW", "kWh" and special services supplied by the Company to the Customer in order to meet the Customer's electric requirements will be priced pursuant to the Customer's standard offer rate otherwise applicable under full requirements service.

All energy produced by the Customer's generator in excess of the Customer's consumption at the time of the production is defined as excess generation and will be tracked throughout the month as excess generation and will be treated in accordance with the provisions outlined below.

EXCESS GENERATION
If at any time within a billing month the Customer's generation facility's energy production exceeds the energy consumed by the Customer, the Customer's bill for the same billing period shall be credited for the excess generation priced at the approved Renewable Credit Rate. In the event the credit exceeds the billable amount during that billing period, the unused credit will carry forward to the bill for the next billing period. The excess generation is treated the same for Standard Offer service Customers and Time-of-Use service Customers.

METERING
The Company will install a bi-directional meter at the point of delivery to the Customer and meter at the point of output from each of the Customer's generators. At the Company's request a dedicated phone line will be provided by the Customer to the metering to allow remote interrogation of the meters at each site. If by mutual agreement between Company and Customer that a phone line is impractical or cannot be provided - the Customer will work with Company to allow for the installation of equipment, on or with Customer facilities or equipment to allow remote access to each meter. Any additional cost of communication, such as but not limited to, cell phone service fees will be the responsibility of the Customer.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RENEWABLE CREDIT RATE
The "Renewable Credit Rate" is the rate equivalent to the most recent utility scale renewable energy purchased power agreement connected to the distribution system of the Company's affiliate, Tucson Electric Power Company, and is set forth in the UNS Electric Statement of Charges.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

Rider R–11
Renewable Credit Rate

AVAILABILITY
The Renewable Credit Rate, Rider R-11, is restricted solely to Rider-10, Net Metering for Certain Partial Requirements Service (NM-PRS), Post June 1, 2015. If at any time within a billing month the Customer's generation facility's energy production exceeds the energy consumed by the Customer, the Customer's bill for the same billing period shall be credited for the excess generation priced at the approved Renewable Credit Rate as described in Rider-10 NM-PRS.

CALCULATION/METHODOLOGY
For production of electricity from a Customer generation facility using Renewable Resources as defined in Rider-10 NM-PRS, the Renewable Credit Rate is the rate equivalent to the most recent utility scale renewable energy Power Purchase Agreement (PPA) connected to the distribution system of the Company's affiliate, Tucson Electric Power Company.

For production of electricity from a Customer generation facility using a Fuel Cell or Combined Heat and Power (CHP) as defined in Rider-10 NM-PRS, the Renewable Credit Rate is the rate equivalent to the most recent utility scale energy PPA connected to the distribution system of the Company's affiliate, Tucson Electric Power Company, that uses a technology specific to the Customer's generation facility at the time service is requested.

If no utility scale PPA meeting the criteria above exists, the Renewable Credit Rate is equal to the UNS Electric Market Cost of Comparable Generation (MCCCG) as defined in Rider-3 MCCCG.

RATE
The Customer monthly bill shall consist of the applicable Rate charges and adjustments in addition to the Credit for Excess Generation based on the RCR as described in Rider-10 NM-PRS. The RCR rate is an amount expressed as a rate per kWh charge that is approved by the ACC on or before January 1 of each year and effective with the first billing cycle in January, as shown in the UNS Electric Statement of Charges.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the ACC see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

Rider R–12
Interruptible Service

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Available to Customers qualifying for and receiving electric service under rates applicable to service over 1,000 kW (either Time-of-Use or Non-Time-of-Use) and are willing to subscribe to at least 500 kW of interruptible load at a contiguous facility. This rider is not available for standby, temporary, resale or in conjunction with other interruptible rates.

CHARACTER OF SERVICE
Must meet all service requirements for the Customer's applicable Standard Offer tariff.

TERMS AND CONDITIONS OF SERVICE

1. Customers taking service under this rider are eligible for credits in exchange for curtailing load at the request of the Company.
2. Interruptions can be called for economic or non-economic reasons and are to be called at the sole discretion of the Company.
3. The Customer must designate each service point that may be available for interruption with a 10 minute notice. Interruption will be at the discretion of the Company.
4. No more than two interruption events will occur in a given calendar day.
5. A Customer will be limited to no more than two interruptions in a day during the five summer months for a maximum of six (6) hours for each daily interruption event, even if the duration per event is less than 6 hours.
6. To receive service under this Rider–12, the Customer will install, at the Customer's expense, all necessary communication, relay and breaker equipment to qualify for service under this rate, subject to Company approval and will pay for associated hardware cost. The Customer must maintain all Company-approved equipment at their service location necessary for the Company to provide interruption notification and to remotely interrupt the Customer from its master control station.
7. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.
8. Nothing herein prevents the Company from interrupting service for emergency circumstances, determined at the Company's sole discretion. Emergency interruptions, as defined by the Company's Rules and Regulations, shall not count as interruption events for purposes of this rider.
9. The standard Rules and Regulations of the Company, as on file with the Arizona Corporation Commission, shall apply where not inconsistent with this rider.
10. The total of all interruption events (excluding Emergency interruptions) will not exceed 120 hours per year.

BID COMMITMENT PERIOD
The Company will post Market Value Capacity Price (MVCP) (defined below) and available Interruptible Credits ($/kW) based on market value capacity for day-ahead dispatch notice for the coming months of May through September by March 15 in the same calendar year.

NOMINATION OF INTERRUPTIBLE LOAD BY CUSTOMER
Nomination will occur before April 15 of the calendar year of each interruption season. Participating Customers shall designate by service point the portion of their load that is Interruptible Load (in kW). A minimum of a thirty minute notice requirement, and a maximum interruption of six hours per event applies to all load nominated at a single service point. Customers with multiple service points may designate different maximum load (kW) for different contiguous service points. If the Customer intends to interrupt a specific activity or function at its operation, the Customer should state this activity or function at the time Interruptible Load is nominated. The minimum nomination of interruptible load summed over a participating Customer's contiguous service points shall be 1,000 kW.

INTERRUPTIBLE CREDIT
Customers who elect service under this Rider–12 will receive a monthly Interruptible credit for each of the five summer months in which an interruption may occur. The credit will be calculated by taking the Market Value Capacity Price applicable for the interruptible load season (May through September) times the nominated interruptible load of the individual Customer.

MARKET VALUE CAPACITY PRICE (MVCP)
The Market Value Capacity Price (MVCP) reflects opportunity cost of capacity as revealed through the Company's resource procurement process, adjusted to reflect line losses, and reserves avoided. Resource prices are sensitive and confidential information based on competitive bids; however this information will be made available to the Commission Staff and/or an Independent Monitor(s) for review. The MVCP is a price applicable to the five summer months only.

RECOVERY OF PROGRAM COSTS
The cost of the interruptible resource under this Rider–12 (the credits applied to qualifying Customers' bills) shall be treated as "Purchased Power" and shall be recorded in FERC account 555 and appropriately treated through the Purchased Power and Fuel Adjustment Clause (PPFAC) as any other prudent fuel or purchased power cost.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rider.

Rider-13
Economic Development Rider (EDR)

AVAILABILITY
Available throughout the Company's entire electric service area at all points where facilities of adequate capacity and required phase and suitable voltage are adjacent to the sites served. This rider is available for commercial or industrial standard offer Customers with a projected peak demand of 1,000 kW or more and a load factor of 75% or higher for the highest 4 coincident-peak months in a rolling 12-month period.

APPLICABILITY
This rider is applicable to the qualifying additional load of an existing or new Customer meeting the criteria specified herein. All provisions of the Customer's applicable standard offer rate will apply to the qualifying additional load, except as modified herein. This rider shall be available for five years from the effective date of the Economic Development Rider. Total program participation shall be limited to 50 MW of applicable Customer load.

New and existing Customers taking service under this rider must provide written documentation that they have qualified for at least one of the following Arizona state tax credits designed to promote business recruitment and expansion:

- Arizona's Quality Jobs Tax Credit (A.R.S. § 41-1525). The program provides a tax credit for net increases in full-time employees residing in the state and hired in qualified employment positions.
    - If located in a city or town with a population of 50,000 persons or more and a county of 800,000 or more, companies must make at least a $5 million capital investment, create at least 25 net new full-time jobs that pay 100 percent of the median county wage, and cover at least 65 percent of employee health insurance costs.
    - In any other location, companies must invest at least $1 million of capital and create at least 5 qualified employment positions.
- Qualified Facility Tax Credit (A.R.S. § 41-1512). The program provides a refundable tax credit for qualifying capital investment in a manufacturing facility – including a manufacturing-related research and development or headquarters facility – that creates new jobs paying at least 125 percent of the median county wage and covering at least 80 percent of employees' health care premiums.

If either or both of the above Arizona Revised Statutes are superseded by subsequent legislation, the effective Statute shall apply. Exceptions to any of the above criteria will be reviewed and evaluated by the Company on a case-by-case basis.

For purposes of this rider, the following notes and/or definitions apply:

[1] Economic Development means new or expanding business operations that build new facilities.

[2] Economic Redevelopment means new or expanding business operations that occupy existing vacant facilities.

CHARACTER OF SERVICE
Must meet all service requirements for the Customer's applicable Standard Offer tariff.

RATE
All provisions, charges, and adjustments in the Customer's applicable Standard Offer retail rate schedule will continue to apply to the qualifying additional load except as follows:

Category	Program Term	Discount on Total Bill before Taxes	Qualifications
Economic Development	5 years	Year 1: 20% Year 2: 15% Year 3: 10% Year 4: 5% Year 5: 2.5%	Meet (i) criteria for Arizona's Quality Jobs Tax Credit or (ii) Qualified Facility Tax Credit and create new/expanding load of 1,000 kW.
Economic Redevelopment	5 years	Year 1: 30% Year 2: 25% Year 3: 20% Year 4: 10% Year 5: 5%	Meet (i) criteria for Arizona's Quality Jobs Tax Credit or (ii) Qualified Facility Tax Credit and create new/expanding load of 1,000 kW, plus the business moves into an existing site.

ECONOMIC DEVELOPMENT RIDER SERVICE AGREEMENT
The Customer must execute an Economic Development Rider Service Agreement with the Company. The Service Agreement establishes the terms and conditions of participation in the program consistent with A.R.S. § 41-1525 and A.R.S. § 41-1512, the Arizona Corporation Commission's regulations, and this rider.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

Experimental Rider-14
Alternative Generation Service (AGS)

AVAILABILITY
Available throughout the Company's entire electric service area at all points where facilities of adequate capacity and required phase and suitable voltage are adjacent to the sites served. This rider is available for standard offer Customers who have a peak load of 2,500 kW or more at a single service point and are served under rates LPS or LPS-TOU.

Customers must have interval metering, advanced metering infrastructure, or an alternative in place at all times under this rider. Customers shall comply with all applicable federal, state, and local laws, regulations, ordinances and codes governing the production and/or sale of electricity.

All provisions of the Customer's applicable standard offer rate will apply in addition to this Experimental Rider-14, except as modified herein. This rider shall be available for four years from the effective date of Experimental Rider-14, unless extended by the Arizona Corporation Commission. Total program participation shall be limited to 10 MW of Customer load.

For purposes of this rider, the following notes and/or definitions apply:

[1] Generation Service means wholesale power delivered to UNS Electric by a Generation Service Provider.

[2] Generation Service Provider means a third party entity that provides wholesale power to the Company on behalf of a Customer. This entity must be legally capable of selling and delivering wholesale power to the Company.

[3] Imbalance Energy means the difference between the hourly delivered energy from the Generation Service Provider and the actual hourly metered loads for each Customer for all Customers that have selected the Generation Service Provider under this rider. Imbalance energy will be calculated by the Company.

[4] Imbalance Service means the calculation and management of the hourly deviations in energy supply for imbalance energy.

[5] Standard Generation Service means power provided by the Company to a retail Customer in conjunction with transmission and delivery services, at terms and prices according to a retail rate other than Experimental Rider-14.

[6] Total Load Requirements means the Customer's hourly load including losses from the point of delivery to the Company's transmission system to the Company's sites for the duration of the contract.

CHARACTER OF SERVICE
The service shall be three-phase, 60 Hertz, and at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

CUSTOMER PARTICIPATION PROCESS
The Company shall establish an initial enrollment period during which Customers can apply for service under this rider. If the applications for service are greater than the program maximum amount, then Customers shall be selected for enrollment through a lottery process as detailed in the program guidelines, which may be revised from time-to-time during the term of this rider.

DESCRIPTION OF SERVICES AND OBLIGATIONS
The Customer shall apply for service under this rider.

The Company shall conduct the enrollment process in accordance with the provisions of this rider.

The Customer shall select a Generation Service Provider to provide Generation Service in accordance with the timeline specified in the program guidelines.

The Company shall enter into a contract with the Generation Service Provider to receive delivery and title to the power on the Customer's behalf.

The Generation Service Provider shall provide to the Company on behalf of the Customer firm power sufficient to meet the Customer's Total Load Requirements for each of the elected metered accounts, and will attest in its contract with the Company that this condition is met. For the purposes of this rider, "firm power" refers to generation resources identified in Western System Power Pool Schedule C or a reasonable equivalent as determined by the Company.

Any incremental costs or penalties incurred by the Company as the result of actions or inactions of the Generation Service Provider will be the responsibility of the Customer to pay or arrange for resolution of or service under this rider will be terminated immediately and the provisions of the section referring to the Default of the Generation Service Provider will be applied.

The Company shall provide transmission, delivery and network services to the Customer according to normal retail electric service.

The Company will settle with the Generation Service Provider for Imbalance Service and other relevant costs on a monthly basis according to the program guidelines.

The Generation Service Provider shall bill the Company the monthly billed amounts for each Customer for Generation Service and Imbalance Service according to the program guidelines.

The Company shall bill the Customer for the Generation Service Provider's charged amounts and remit the amounts to the Generation Service provider including any applicable taxes and assessments.

The Customer will be responsible for paying for the cost of the power provided by the Generation Service Provider, as specified in the contract and this rider and will be subject to disconnection in the manner consistent with the Rules and Regulations for the equivalent retail service in the event of non-payment or late payment.

RATE
All provisions, charges, and adjustments in the Customer's applicable retail rate schedule will continue to apply except as follows:

1. The Base Power Charge will not apply.
2. The unbundled Generation components of the Demand Charge and Energy Charge for Delivery Services will not apply.
3. The Purchased Power and Fuel Adjustment Clause (PPFAC) will not apply, except that the Historical Component will apply for the first twelve months of service under this rider.

Experimental Rider-14 charges determined and billed by the Company include:

1. A monthly Management Fee of $0.0040 per kWh applied to the Customer's metered kWh.
2. A monthly Reserve Capacity charge equal to the applicable unbundled Generation components of the Demand Charge and the Energy Charge for Delivery Services will be applied to the Customer's billed kW and kWh, respectively. The Reserve Capacity charge will be applied to 100% of the Customer's monthly billed kW and kWh during the first twelve months of service under this rider and 25% of the Customer's billed kW and kWh thereafter until the expiration date of this Rider.
3. An initial charge or credit for fuel hedging costs, as describe herein.
4. Returning Customer charge, where applicable, as described herein.
5. Generation Service Provider Default charge, where applicable, as described herein.

Experimental Rider-14 Generation Service and Imbalance Service charges billed by the Company include:

1. Generation Service charges shall be charged at a rate specified in the contract between the Customer and the Generation Service Provider.
2. Imbalance Service charges shall be charged at a rate greater than $0.00 per kWh and less than or equal to the rate that the Company charges the Generation Service Provider for Imbalance Service as specified herein.

DELIVERY OF POWER TO THE COMPANY'S SYSTEM
Power provided by the Generation Service Provider must be firm power as defined above and delivered to the Company at a point of delivery as agreed to by the Company. The Generation Service Provider is responsible for the cost of transmission service to deliver the power to the Company's delivery point.

SCHEDULING
The Company shall serve as the scheduling coordinator. The Generation Service Provider shall provide monthly schedules of hourly loads along with day-ahead hourly load deviations from the monthly schedule to the Company according to the program guidelines. Line losses, in the amount of 3.3%, from the point of delivery to the Customer's sites shall be either scheduled or financially settled.

IMBALANCE SERVICE
The Company will provide Imbalance Service according to the terms and provisions in the Company's Open Access Transmission Tariff, Schedule 4. Imbalance Energy will be based on the Generation Service Provider's portfolio of Customer loads.

PPFAC AND HEDGE COST TRUE-UP
The Customer will be subject to the Purchased Power and Fuel Adjustment Clause (PPFAC) – historical component for the first twelve months of service under this rider. The Customer will also pay for the hedge cost associated with the Customer's Standard Generation Service at the time the Customer takes service under this rider. For the purpose of this rider, the Company will determine the applicable pro rata hedge cost based on the market price for hedge costs at the time the Customer takes service under this rider.

CONTRACT TERM AND REQUIREMENTS
The term of the contract with the Generation Service Provider shall be for not less than one year and shall not exceed the termination date of this rider or 4 years, whichever is shorter.

The Generation Service Provider and Customer will enter into a contract or contracts with the Company, stating the pertinent details of the transaction with the Generation Service Provider, including but not limited to the scheduling of power, location of delivery, and other terms related to the Company's management of the generation resource.

DEFAULT OF THE THIRD PARTY GENERATION SERVICE PROVIDER

In the event that the Generation Service Provider is unable to meet its contractual obligations, the Customer must notify the Company and select another Generation Service Provider within 60 days. Prior to execution of any new power contract, the Company shall provide the required power to the Customer, which will be charged at the Dow Jones Electricity Palo Verde Daily Index price for the power delivery date plus $20 per MWh. In addition, all other provisions of this rider will continue to apply.

If the Customer is unable to select another Generation Service Provider within sixty days, the Customer will automatically return to Standard Generation Service, and be subject to the conditions below.

RETURN TO COMPANY'S STANDARD GENERATION SERVICE

Customer may return to the Company's Standard Generation Service under their applicable retail rate schedule without charge if: (1) they provide one year notice (or longer) to the Company; or (2) if this rider is discontinued at the end of the 4-year experimental period; or (3) the Commission terminates the program prior to the end of the initial 4-year experimental period. Absent one of these three conditions, the Company will provide the Customer with generation service at the Dow Jones Electricity Palo Verde Daily Index price for the power delivery date plus $20 per MWh until the Company is reasonably able to integrate the Customer back into their generation planning and provide power at the applicable retail rate schedule. This transition will be at the Company's determination but no longer than 1 year. The returning Customer must remain with the Company's Standard Generation Service for at least 1 year and compensate the Company for all fixed generation costs avoided by the Customer during the period the Customer was receiving service under this rider.

LOST FIXED COST RECOVERY

UNS Electric will track all non-recovered revenues related to generation fixed costs for future recovery in the Company's Lost Fixed Cost Recovery (LFCR).

CREDIT REQUIREMENTS

A Generation Service Provider or its parent company must have at least an investment grade credit rating or demonstrate creditworthiness in the form of either a 3rd-party guarantee from an investment grade rated company, surety bond, letter of credit, or cash in accordance with the Company's standard credit support rules.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

UNS ELECTRIC STATEMENT OF CHARGES

Fee No.	Description	Rate	Effective Date	Decision No.
1.	Service Transfer Fee	$26.00	Pending	Pending
2.	Customer-Requested Meter Re-read	$26.00	Pending	Pending
3.	Special Meter Reading Fee (including Customer Self-Reads)	$26.00	Pending	Pending
4.	Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures During Regular Business Hours	$47.00	Pending	Pending
5.	Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures After Regular Business Hours (includes Saturdays, Sundays and Holidays)	$149.00	Pending	Pending
6.	Service Reestablishment under other than usual operating procedures (including Automated Meter Opt-Out Set Up Fee)	$196.00	Pending	Pending
7.	Meter Test	$79.00	Pending	Pending
8.	Consumption History Request and Interval History Request	$65.00 per hour	Pending	Pending
9.	Returned Payment Fee	$10.00	Pending	Pending
10.	Late Payment Finance Charge	1.5%	Pending	Pending

UniSourceEnergy SERVICES

UNS Electric, Inc.

Substitute Original Sheet No.: 801-1

Superseding Original Sheet No.: 801-1

UNS ELECTRIC STATEMENT OF CHARGES

Description	Rate	Effective Date	Decision No.
Rider R-1 – Purchased Power and Fuel Adjustment Clause (PPFAC)	Varies–See Rider-1	January 1, 2014	74235
Rider R-2 – Demand Side Management Surcharge (DSMS)	$0.0015 per kWh	August 1, 2014	74599
Rider R-3 – Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS	$0.03697 per kWh	June 1, 2014	74387
Rider R-5 – Electric Service Solar Rider (Bright Arizona Community Solar™) Solar Block Energy Rate for Residential Electric Service, Rate R-01 Solar Block Energy Rate for General Service, Rate SGS-10 Solar Block Energy Rate for Large General Service, Rate LGS	 $0.087445 per kWh $0.085495 per kWh $0.077991 per kWh	January 1, 2011 through December 31, 2013	72034
Rider R-5 – Electric Service Solar Rider (Bright Arizona Community Solar™) Solar Block Energy Rate for Residential Electric Service, Rate R-01 Solar Block Energy Rate for General Service, Rate SGS-10 Solar Block Energy Rate for Large General Service, Rate LGS	 $0.084510 per kWh $0.078241 per kWh $0.076603 per kWh	January 1, 2014 Through pending	74235
Rider R-5 – Electric Service Solar Rider (Bright Arizona Community Solar™) Solar Block Energy Rate for Residential Electric Service, Rate R-01 Solar Block Energy Rate for General Service, Rate SGS-10 Solar Block Energy Rate for Medium General Service, Rate MGS	 $0.069260 per kWh $0.068610 per kWh $0.068440 per kWh	Pending	Pending
Rider R-6 – Renewable Energy Standard and Tariff Surcharge REST-TS1 Renewable Energy Program Expense Recovery Monthly Cap For Residential Customers: For Commercial Customers: For Industrial Customers: For Lighting (PSHL):	$0.01000 per kWh Monthly Cap $3.40 per month $90.00 per month $10,000 per month $90.00 per month	January 1, 2015	74877

UniSourceEnergy SERVICES

UNS Electric, Inc.

Substitute Original Sheet No.: 801-2

Superseding Original Sheet No.: 801-2

UNS ELECTRIC STATEMENT OF CHARGES

Description	Rate	Effective Date	Decision No.
Rider R-6 – Renewable Energy Standard and Tariff Surcharge REST-TS1 Renewable Energy Program Expense Recovery Per Decision No. 73638, customers receiving incentives on or after January 1, 2012 shall pay the average of the REST surcharge paid by members of their customer class. Customer with renewable installations without incentives that is interconnected with UNSE's system on or after February 1, 2013 shall pay the average of the REST surcharge paid by members of their customer class. The average price by class shall be the following: Monthly Cap For Residential Customers: For Commercial Customers: For Industrial Customers: For Lighting (PSHL):	Monthly Cap $3.00 per month $19.50 per month $9,763 per month $1.30 per month	January 1, 2015	74877
Rider R-8 Lost Fixed Cost Recovery (LFCR) Mechanism	Pending	Pending	Pending
Rider R-9 Transmission Cost Adjustor (TCA) – $/kWh charge (Non-Demand) Transmission Cost Adjustor (TCA) – $/kW charge (Demand)	$0.00114 per kWh $0.4329 per kW	June 9, 2014	74235
Rider R-11 Renewable Credit Rate	Pending	Pending	Pending

Filed By: Kentton C. Grant
Title: Vice President
District: Entire Electric Service Area

Rate: Statement of Charges
Effective: Pending
Decision No.: Pending

Bill Estimation Methodologies

UNS Electric, Inc. (UNS Electric) regularly encounters situations in which UNS Electric cannot obtain a complete and valid meter read. No matter the cause of the need to estimate the read, the following methods are used depending on the circumstances.

PREVIOUS YEAR FORMULA

SAME CUSTOMER WITH AT LEAST ONE YEAR OF HISTORY

UNS Electric would generate a bill based on Customer usage from the previous year using the "PREVIOUS YEAR" formula as follows:

LAST YEAR'S USAGE FOR SAME MONTH / NUMBER OF DAYS IN BILLING PERIOD = PER DAY USAGE
(FOR "TIME OF USE" (TOU) THIS WOULD BE APPLIED TO EACH PERIOD)

PER DAY USAGE X NUMBER OF DAYS IN THIS MONTH'S CYCLE = ESTIMATED USAGE
(FOR TOU THIS WOULD BE APPLIED TO EACH PERIOD)

PREVIOUS MONTH FORMULA

SAME CUSTOMER AT SAME PREMISE WITH LESS THAN ONE YEAR OF HISTORY

UNS Electric would generate a bill based on Customer usage from the previous month using the "PREVIOUS MONTH" formula as follows:

LAST MONTHS USAGE / NUMBER OF DAYS IN BILLING PERIOD = PER DAY USAGE
(FOR TOU THIS WOULD BE APPLIED TO EACH PERIOD)

PER DAY USAGE X NUMBER OF DAYS IN THIS MONTH'S CYCLE = ESTIMATED USAGE
(FOR TOU THIS WOULD BE APPLIED TO EACH PERIOD)

TREND FORMULA

NEW CUSTOMER AT SAME PREMISE

UNS Electric would generate a bill using the "TREND" formula, based on Customer's usage trend as described below:

UNS Electric's customer information system (CIS) would generate a bill based on trend. Customers are assigned to a Trend area which differentiate consumption based on different geographic areas. Secondly, the Customer is assigned to a Trend class which is used to differentiate consumption trends based on the type of service and type of property. An example of this would be residential, commercial, and industrial usage. Thirdly, all consumption is identified using unit of measure code and a time of use code. Within UNS Electric's CIS, a trend record is created from each billed service. This record becomes part of a trend table. During estimation, consumption from three prior bill cycles is compared to the consumption from the same cycle in the previous month to determine a trend. This trend, plus a tolerance, is used to create a usage amount for bill estimation.

CUSTOMER'S USAGE IN PREVIOUS PERIOD/ AVERAGE CUSTOMER'S USAGE IN PREVIOUS PERIOD X AVERAGE CUSTOMER'S USAGE IN CURRENT PERIOD = ESTIMATED CONSUMPTION FOR REGISTER READ

NO HISTORY

UNS Electric would not generate a bill until a good meter read was acquired then use known consumption to estimate previous bills.

Demand Estimate

For accounts that have a demand billing component UNS Electric collects interval data. This interval data is used to manually estimate demands using the following methodologies:

SAME CUSTOMER AT SAME PREMISE WITH AT LEAST ONE YEAR OF HISTORY

UNS Electric would generate a bill based on Customer usage from the previous year using the following formula:

LAST YEAR'S DEMAND FOR SAME MONTH = ESTIMATED DEMAND

NEW CUSTOMER AT SAME PREMISE WITH AT LEAST ONE YEAR OF HISTORY

UNS Electric would generate a bill based on Customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

SAME CUSTOMER AT SAME PREMISE WITH LESS THAN ONE YEAR OF HISTORY

UNS Electric would generate a bill based on Customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

NEW CUSTOMER AT SAME PREMISE WITH LESS THAN ONE YEAR OF HISTORY

UNS Electric would generate a bill based on Customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

NO HISTORY

UNS Electric would not generate a bill until a good demand read was acquired then use known demand to estimate previous bills.

GUIDELINES FOR ELECTRIC LOAD CURTAILMENT

INTRODUCTION
While UNS Electric, Inc. (UNS Electric) strives to provide an uninterrupted supply of electricity, conditions could exist on UNS Electric's electric power system where:

- The power supply would be insufficient to meet the electric load demands during peak period. This condition will be classified as a "Bulk Power Supply Emergency".
- The transmission delivery would be insufficient to meet electric load demands. This will be considered a "Transmission Emergency".

Should a "Bulk Power Supply Emergency" or a "Transmission Emergency" seem imminent the following steps will be implemented as appropriate.

1. Evaluate alternative power supplies or Company owned generation.
2. Call on Interruptible Customers to interrupt load.
3. Reschedule any scheduled maintenance of the transmission system.
4. Reduce all non-essential Company uses such as office lighting, electric cooling and heating, etc.
5. Contact Western Area Power Administration for possible assistance.
6. Contact Nevada Energy and Aha Macav Power Service for possible emergency assistance.
7. Reduce distribution feeder voltage up to 5%, where possible.

Should additional remedial action be warranted, UNS Electric will make a public appeal via local radio stations and television for the voluntary curtailment of electric consumption by its customers.

Should voluntary curtailment result in insufficient load reduction to mitigate the emergency, the Arizona Corporation Commission (ACC) has directed UNS Electric to institute mandatory involuntary curtailment, pursuant to ACC Decision No. 42097 and Arizona Administrative Code R14-2-208, Provision of Service, Paragraph E.

CUSTOMER LOAD DEFINITIONS

Essential Loads: Loads that are necessary to the health, safety and welfare of the public or some portion or member thereof, such as police, fire service, national defense, sewage facilities, domestic water facilities, hospitals, essential medical devices (such as iron lungs, oxygen pumps or similar uses) and where uninterrupted electric service is essential to the providing of such essential uses or services. These loads will not be interrupted unless an area needs to be dropped to maintain the stability of the electric system, or adequate on-site generation is available to cover the Essential load.

Critical Loads: That portion of the electric load of those non-residential customers which in the event of interruption of service would cause excessive damage to the equipment or material in process or perishable items or where such interruption would create grave hazards to the employee's or the public. These areas will not be interrupted unless an area needs to be dropped to maintain the stability of the electric system, or adequate on–site generation is available to cover the Critical load level.

Others: All customers not meeting the above definitions will be interrupted, with or without, notice if voluntary curtailment measures are not sufficient to alleviate the problem.

LOAD CURTAILMENT NOTIFICATION

UNS Electric's load is served primarily by Tucson Electric Power Company (TEP) under a Power Services Agreement. Energy from TEP resources is delivered to UNS Electric's load areas in Mohave and Santa Cruz Counties through the bulk power transmission system of the Western Area Power Administration (WAPA). UNS Electric's load is in the control area of TEP for Power Supply purposes and in WAPA's control area for Transmission purposes. Either control area could initiate a call for load curtailment due to a system or regional power supply or transmission emergency. Local Transmission Emergencies could occur, affecting portions of UNS Electric's service area only.

Should either voluntary or involuntary load curtailment become necessary:

1. UNS Electric's Mohave Dispatch Center will be notified of a regional curtailment emergency by either TEP's Energy Control Center or the WAPA's Transmission Dispatch Desk.

2. UNS Electric's Mohave Dispatch Center will notify Mohave Management of the nature and type of curtailment emergency.

3. Mohave Management will notify Company Management, District Operations Management and the ACC of the nature of the curtailment.

4. District Customer Service Personnel will, if time permits:

    - Notify Interruptible Customer to drop load;
    - Notify key customers of the nature of the curtailment and request voluntary load; reductions or activation of on-site generation (if any);
    - Call local radio stations to request public announcements;
    - Notify County Emergency Management, and;
    - Notify City and County Police and Fire Departments.

5. District Operations Personnel will notify supervisory and assigned staff to report to their respective duty stations.

VOLUNTARY LOAD CURTAILMENT
If conditions allow for advanced notification, UNS Electric shall evaluate activating its own generation and will ask the public for a voluntary curtailment. In addition, all Interruptible Customers and Large Load Customers will be called by pre-assigned individuals to request load interruption as provided for under the Tariff or voluntary load reduction where no tariff exists.

INVOLUNTARY LOAD CURTAILMENT
Should the voluntary curtailment result in an insufficient reduction in load, Division Operations Management will determine the amount of additional load to curtail. Blackout periods are to be approximately 30 to 60 minutes in duration.

After proper notification Division Operations Management will utilize the capabilities of the System Control and Data Acquisition System ("SCADA") and manual operation to shed load throughout the District operations areas (Kingman, Lake Havasu City and Santa Cruz) based on circuit classification, unless the emergency is of a local nature. Individual Distribution Circuits will be classified for curtailment, according to the type of customers served on that feeder, as defined in the Guide to Circuit Loading for each District.

DISTRIBUTION CIRCUIT CLASSIFICATIONS
Essential: Circuits that serve essential customers will be so identified and will not be interrupted, unless an area must be dropped to maintain electric system stability.

Critical: Circuits that serve critical customers will be so identified and will not be interrupted, unless an area must be dropped to maintain electric system stability. Critical Customers will be notified and required to curtail the non-critical portions of their load. If a customer with a critical load refuses or fails to curtail their electric consumption down to the critical load, the customer shall not be considered to have a critical load and can be curtailed 100%.

Large Load Customers:

1. Circuits that serve Large Load Customers will be so identified and will not be interrupted until proper notice is given, unless an area must be dropped to maintain electric system stability.

2. Customers, who can take 100 percent curtailment if given sufficient notice, will be rotated on the same schedule as the "Others" circuits until the emergency is terminated by UNS Electric.

3. Customers served by circuits that cannot be rotated* will be notified. They will be required to reduce their load to their pre-determined level, in a rotating order and with a frequency or repetition necessary to meet the emergency situation.

Others:
Circuits that serve all remaining customers will be so identified and rotated without notice. Rotation of these circuits will be for a duration and frequency necessary to meet the emergency situation.

Customers on a non-rotating circuit* who normally could be rotated, will be required to curtail load. If these customers do not curtail to the extent needed, UNS Electric may discontinue or disconnect service and refuse to re-establish service until after the emergency condition is terminated.

***Non-Rotating Circuits are so classified based on the specific nature of the electric distribution system or due to having critical or essential customers served by that feeder.**

EMERGENCY INVOLUNTARY CURTAILMENT
In the event a major electrical disturbance threatens the interconnected Southwest system with blackout conditions or/and unexpected shortages of power that do not allow for the implementation of the Electric Curtailment Plan, emergency devices such as under-frequency/under-voltage load shedding relays will automatically shed load to maintain system stability, and the Company will resort to emergency operating procedures. These circuits will remain out of service until the Company can move from the emergency procedure to the Electric Load Curtailment Plan or the emergency is resolved.

INVOLUNTARY CURTAILMENT BY TRANSMISSION PROVIDER
UNS Electric purchases transmission service from the WAPA to deliver its power supply requirements. WAPA's Transmission Dispatch Desk would notify the UNS Electric Arizona Dispatch Center of situations on the bulk transmission system requiring load curtailment in the Company's service area.

ELECTRIC LOAD AND CURTAILMENT PLAN
A detailed electric load and curtailment plan will be kept on file with the ACC. This plan will contain specific procedures for implementation of the above, along with the name(s) and telephone number(s) of the appropriate Company personnel to contact in the event implementation of the plan becomes necessary. Updates to the plan will be filed annually or when they occur. Its amendments will become effective upon submission to the ACC.

The Company will contact the Director of the Utilities Division, or their designee, as soon as practical for any curtailment pursuant to this Tariff.

Rates for Power and Energy Transactions With Qualifying Facilities That Receive Full Requirements 100 kW or Less (QF-A)

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises. For all Qualifying Facilities (QF) that have entered into a Service Agreement with the Company.

APPLICABILITY
To all QFs with 100 kW or less operating in the Buy/Sell Mode for full requirements, supplemental power, stand-by power, and maintenance power service. To take service under QF-A, the customer must take service under a standard offer rate option with a demand charge.

CHARACTER OF SERVICE
Electric sales to the Company must be single or three phase, 60 Hertz, at a standard voltage subject to availability at the premises. The QF will have the option to sell energy to the Company at a voltage level different from that for purchases from the Company, however, the QF will be responsible for all costs incurred to accommodate such an arrangement.

DEFINITIONS

1. Qualifying Facilities - Cogeneration and small power production facilities where the facility's generator(s) and load are located at the same premise and that otherwise meet qualifying criteria for size, fuel use, efficiency and ownership as promulgated in 18 C.F.R., Chapter I, Part 292, Subpart B of Federal Energy Regulatory Commission regulations.

2. Buy/Sell Mode of Operation - The QF's total generation output is delivered to the Company and the QF's full requirements for service are provided by the Company or no electric requirements are required by the QF.

3. Full Requirements Service - Any instance whereby the Company provides all the electric requirements of a QF.

4. Energy - Electric energy which is supplied by the QF.

5. Firm Capacity - Capacity available, upon demand, at all times (except for forced outages and scheduled maintenance) during the period covered by the Agreement from the QF with an availability factor of at least 80%, as defined by the North American Electric Reliability Council.

6. Net Energy - The total kilowatt hours (kWh) sold to the QF by the company less the total kWhs purchased by the Company from the QF.

7. Supplemental Power - Electric capacity and energy supplied by the Company regularly used by the QF in addition to that which the facility generates itself.

8. Stand-by Power - Electric capacity and energy supplied by the Company to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

9. Maintenance Power - Electric capacity and energy supplied by the Company during scheduled outages of the QF.

10. Purchase Agreement - Agreements for the purchase of electric energy and capacity from and the sale of power to the QF entered into between the Company and QF.

Net Bill method:
The kWhs sold to the Company shall be subtracted from the kWhs purchased from the Company. If the calculation is positive, the Net Energy kWhs received from the Company will be priced at the applicable Electric Rate under which the QF would otherwise purchase its full requirements service. If the calculation is negative, the Net Energy kWhs delivered to the Company will be priced at the purchase rate shown below.

RATES FOR SALES TO QFs
The rates and billings for sales of energy and capacity to the QF shall be billed pursuant to the Customer's standard offer tariff otherwise applicable under full requirements service.

RATES FOR PURCHASES FROM QFs
Basic Service charges shall be billed pursuant to the Customer's standard offer tariff otherwise applicable under full requirements of service.

Rates for Energy purchased from the QF shall be priced at short-run avoided cost.

Rates for Firm Capacity purchased from the QF shall be priced at avoided cost based upon deferral of capacity additions indicated in Company's resource plan.

ADJUSTMENTS
Purchased Power Fuel Adjuster Clause (PPFAC) is a percent monthly adjustment in accordance with the PPFAC Rider No. 1. The PPFAC reflects increases or decreases in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. See Rider-1 for current rate.

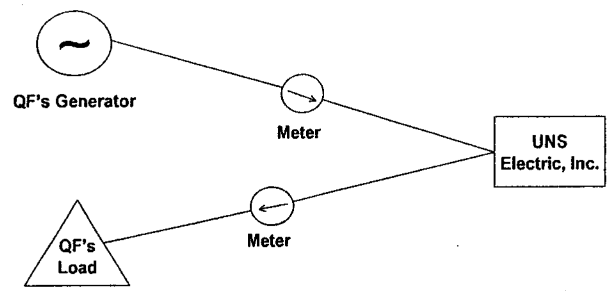
CONTRACT PERIOD
As provided for in the Service Agreement.

TERMS AND CONDITIONS
Subject to:

The Service Agreement, and

A delayed payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

METER CONFIGURATION



UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rate.

Rates for Power and Energy Transactions With Qualifying Facilities That Receive Partial Requirements 100 kW or Less (QF-B)

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises. For all Qualifying Facilities (QF) that have entered into a Service Agreement with the Company.

APPLICABILITY
To all QFs with 100 kW or less operating in the Partial Requirements Mode for partial requirements, supplemental power, stand-by power, and maintenance power service. To take service under QF-B, the customer must take service under a standard offer rate option with a demand charge.

CHARACTER OF SERVICE
Electric sales to the Company must be single or three phase, 60 Hertz, at a standard voltage subject to availability at the premises. The QF will have the option to sell energy to the Company at a voltage level different from that for purchases from the Company, however, the QF will be responsible for all costs incurred to accommodate such an arrangement.

DEFINITIONS

1. Qualifying Facilities - Cogeneration and small power production facilities where the facility's generator(s) and load are located at the same premise and that otherwise meet qualifying criteria for size, fuel use, efficiency and ownership as promulgated in 18 C.F.R., Chapter I, Part 292, Subpart B of Federal Energy Regulatory Commission regulations.

2. Partial Requirements Mode of Operation - A QF's generation output first goes to supply its own electric requirements with any excess energy (over and above its own requirements) then being sold to the Company. The Company supplies the QF's electric requirements not met by the QF's own-generation facilities. This also may be referred to as the "parallel mode" of operation.

3. Energy - Electric energy which is supplied by the QF

4. Firm Capacity - Capacity available, upon demand, at all times (except for forced outages and scheduled maintenance) during the period covered by the Agreement from the QF with an availability factor of at least 80%, as defined by the North American Electric Reliability Council.

5. Net Energy - The total kilowatt hours (kWh) sold to the QF by the company less the total kWhs purchased by the Company from the QF.

6. Supplemental Power - Electric capacity and energy supplied by the Company regularly used by the QF in addition to that which the facility generates itself.

7. Stand-by Power - Electric capacity and energy supplied by the Company to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

8. Maintenance Power - Electric capacity and energy supplied by the Company during scheduled outages of the QF.

9. Purchase Agreement - Agreements for the purchase of electric energy and capacity from and the sale of power to the QF entered into between the Company and QF.

RATES FOR SALES TO QFs
The rates and billings for sales of energy and capacity to the QF shall be billed pursuant to the Customer's standard offer tariff otherwise applicable under full requirements service.

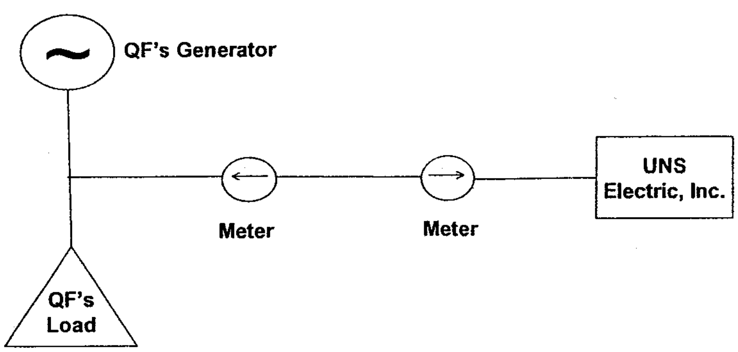
RATES FOR PURCHASES FROM QFs
Basic Service charges shall be billed pursuant to the Customer's standard offer tariff otherwise applicable under full requirements of service.

Rates for Energy purchased from the QF shall be priced at short-run avoided cost.

Rates for Firm Capacity purchased from the QF shall be priced at avoided cost based upon deferral of capacity additions indicated in Company's resource plan.

ADJUSTMENTS
Purchased Power Fuel Adjuster Clause (PPFAC) is a percent monthly adjustment in accordance with the PPFAC Rider No. 1. The PPFAC reflects any increases or decreases in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. See Rider-1 for current rate.

METER CONFIGURATION



CONTRACT PERIOD
As provided for in the Service Agreement.

TERMS AND CONDITIONS
Subject to:

The Service Agreement, and

A delayed payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rate.

Rates for Power and Energy Transactions With Qualifying Facilities That Receive Optional Service Over 100 kW (QF-C)

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises. For all Qualifying Facilities (QF) that have entered into a Service Agreement with the Company.

APPLICABILITY
To all QFs with over 100 kW operating in the Partial Requirements Mode for partial requirements, supplemental power, stand-by power, and maintenance power service.

CHARACTER OF SERVICE
Electric sales to the Company must be single or three phase, 60 Hertz, at a standard voltage subject to availability at the premises. The QF will have the option to sell energy to the Company at a voltage level different from that for purchases from the Company, however, the QF will be responsible for all costs incurred to accommodate such an arrangement.

DEFINITIONS

1. Qualifying Facilities - Cogeneration and small power production facilities where the facility's generator(s) and load are located at the same premise and that otherwise meet qualifying criteria for size, fuel use, efficiency and ownership as promulgated in 18 C.F.R., Chapter I, Part 292, Subpart B of Federal Energy Regulatory Commission regulations.

2. Partial Requirements Mode of Operation - A QF's generation output first goes to supply its own electric requirements with any excess energy (over and above its own requirements) then being sold to the Company. The Company supplies the QF's electric requirements not met by the QF's own-generating facilities. This also may be referred to as the "parallel mode" of operation.

3. Energy - Electric energy which is supplied by the QF.

4. Firm Capacity - Capacity available, upon demand, at all times (except for forced outages and scheduled maintenance) during the period covered by the Agreement from the QF with an availability factor of at least 80%, as defined by the North American Electric Reliability Council.

5. Net Energy - The total kilowatt hours (kWh) sold to the QF by the company less the total kWhs purchased by the Company from the QF.

6. Supplemental Power - Electric capacity and energy supplied by the Company regularly used by the QF in addition to that which the facility generates itself.

7. Stand-by Power - Electric capacity and energy supplied by the Company to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

8. Maintenance Power - Electric capacity and energy supplied by the Company during scheduled outages of the QF.

9. Purchase Agreement - Agreements for the purchase of electric energy and capacity from and the sale of power to the QF entered into between the Company and QF.

RATES FOR SALES TO QFs

Supplemental Service:

A. Service Charge - The service charge shall be the basic service charge using the otherwise applicable retail Rate.

B. Energy Charge - The energy charge shall be the energy charge using the otherwise applicable retail Rate.

C. Demand Charge - The demand charge shall be the demand charge using the otherwise applicable retail Rate and it shall apply only to supplemental power and not to total requirements.

Standby Service:

A. Service Charge - The service charge shall be the basic service charge using the otherwise applicable retail Rate.

B. Energy Charge - The energy charge is $0.0538 per kWh per month.

C. Demand Charge - The demand charge shall be the product of $25.92 per kW per month and the probability (*) that the QF has an unscheduled outage at the time of the company's peak.

(*) This value is initially set at ten percent (10%) for the first year and reset annually based upon actual experience with the QF.

Maintenance Service:

A. Service Charge - The service charge shall be the basic service charge using the otherwise applicable retail Rate.

B. Energy Charge - The energy charge is $0.0538 per kWh per month.

C. Maintenance Service - Must be scheduled with the Company and may only be scheduled during the period October through April.

Only one service charge will be applied for each billing period.

RATES FOR PURCHASES FROM QFs

Basic Service charges shall be billed pursuant to the Customer's standard offer tariff otherwise applicable under full requirements of service.

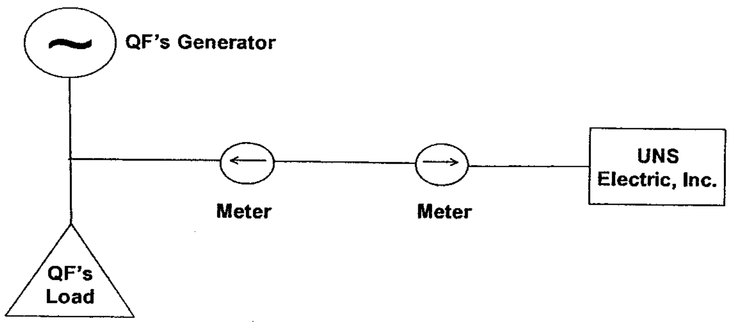
Rates for Firm Capacity purchased from the QF shall be priced at long-run avoided cost based upon deferral of capacity additions indicated in Company's resource plan.

Rates for capacity associated with Firm Capacity shall be as provided for in the Service Agreement.

ADJUSTMENTS

Purchased Power Fuel Adjuster Clause (PPFAC)is a percent monthly adjustment in accordance with the PPFAC Rider No. 1. The PPFAC reflects any increases or decreases in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. See Rider-1 for current rate.

METER CONFIGURATION



CONTRACT PERIOD
As provided for in the Service Agreement.

TERMS AND CONDITIONS
Subject to:

The Service Agreement, and

Shall be interconnected with and can operate in parallel and in phase with the Company's existing distribution system. The Interconnection must comply with the Company's interconnection requirements, and

Shall take service as a Primary Service and Metering Customer (the Company shall not provide voltage transformation on the customer's premise).

A delayed payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rate.

Exhibit CAJ-4

Residential Service (RES-01)

AVAILABILITY

Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to ~~individual motors exceeding 40 amperes at a rating of 230 volts or which will~~electrical equipment that causes excessive voltage fluctuations.

CHARACTER OF SERVICE

The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE

A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF ~~CUSTOMER~~BASIC SERVICE AND ENERGY CHARGES

~~Customer Charges:~~
~~Standard~~
~~Customer~~Basic Service Charge ~~and minimum bill~~ — $~~1~~20.00 per month

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option~~
~~CustomerBasic Service Charge with usage less than 2,000 kWh — $12.50 per month~~
~~CustomerBasic Service Charge with usage of 2,000 kWh or more — $16.50 per month~~

Energy Charges (per kWh):

	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
0 - 400 kWh	$0.030810~~019300~~	$0.049260~~064510~~	Varies	$0.080070~~083810~~
~~401 – 1,000~~Over 400 kWh	$0.050810~~034350~~	$0.049260~~064510~~	Varies	$0.100070~~098860~~
~~Over 1,000 kwh~~	~~$0.038499~~	~~$0.064510~~	~~Varies~~	~~$0.103009~~

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent ~~kWh~~ adjustment in accordance with ~~Rate~~ Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold~~. Please see Rider-1 for current rate.

3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

UniSourceEnergy SERVICES

UNS Electric, Inc.

~~1st Substitute~~ Original Sheet No.: 101-1

Superseding: ~~Original Sheet No. 101~~

MONTHLY CUSTOMER ASSISTANCE RESIDENTIAL ENERGY SUPPORT (CARES) DISCOUNT:
This discount is only available to new and eligible CARES Customers whose monthly bill shall be in accordance to the rate above except that a discount of $10.00 per month shall be applied. No CARES discount will be applied that will reduce the bill to less than zero.

CARES ELIGIBILITY

1. The UNS Electric account must be in the Customer's name applying for a CARES discount.
2. Applicant must be a UNS Electric residential Customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on UNS Electric's website at www.uesaz.com or contact a UNS Electric customer care representative.

~~LOST FIXED COST RECOVERY (LFCR) – RIDER 8~~
~~For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly CustomerBasic Service Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly CustomerBasic Service Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly CustomerBasic Service Charge for a completecontiguous twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.~~

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

~~Customer~~Basic Service Charge Components (Unbundled):

~~Standard~~	
Description	
Meter Services	$ 1.38~~1.83~~ per month
Meter Reading	$ 0.89~~2.08~~ per month
Billing & Collection	$ 6.01~~4.92~~ per month
Customer Delivery	$ -11.72~~1.17~~ per month
Total	$ 20.00~~10.00~~ per month

UniSourceEnergy SERVICES

UNS Electric, Inc.

~~1st Substitute~~ Original Sheet No.: 101-3

Superseding: ~~Original Sheet No. 101~~

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh~~	
~~Description~~	
~~Meter Services~~	~~$ 1.83 per month~~
~~Meter Reading~~	~~$ 2.08 per month~~
~~Billing & Collection~~	~~$ 4.92 per month~~
~~Customer Delivery~~	~~$ 1.17 per month~~
~~LFCR~~	~~$ 2.50 per month~~
~~Total~~	~~$12.50 per month~~

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more~~	
~~Description~~	
~~Meter Services~~	~~$ 1.83 per month~~
~~Meter Reading~~	~~$ 2.08 per month~~
~~Billing & Collection~~	~~$ 4.92 per month~~
~~Customer Delivery~~	~~$ 1.17 per month~~
~~LFCR~~	~~$ 6.50 per month~~
~~Total~~	~~$16.50 per month~~

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	~~Rate~~
0 – 400 kWh	$0.009160~~005271~~
~~401 – 1,000~~Over 400 kWh	$0.029160~~020321~~
~~Over 1,000 kWh~~	~~$0.024470~~
Generation Capacity	$0.010980~~008325~~
Transmission	$0.010670~~005704~~

Power Supply Charges ~~(per kWh)~~:

Component	~~Rate~~
Base Power Supply (per kWh)	$0.049260~~064510~~
PPFAC (%) (see Rider-1 for current rate)	Varies

Filed By:	Kentton C. Grant	Rate:	RES-01
Title:	Vice President	Effective:	~~January 1, 2014~~Pending
District:	Entire Electric Service Area	Decision No:	~~74235~~Pending

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 102
Superseding:

Residential Service Time-of-Use (RES-01 TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to ~~individual motors exceeding 40 amperes at a rating of 230 volts or which will~~electrical equipment that causes excessive voltage fluctuations.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

Service under this rate will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF ~~CUSTOMER~~BASIC SERVICE AND ENERGY CHARGES

~~Customer Charges:~~	
~~Standard~~	
~~Customer~~Basic Service Charge ~~and minimum bill~~	$~~11.50~~20.00 per month
~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option~~	
~~CustomerBasic Service Charge with usage less than 2,000 kWh~~	~~$14.00 per month~~
~~CustomerBasic Service Charge with usage of 2,000 kWh or more~~	~~$18.00 per month~~

Energy Charges (per kWh):

Filed By:	Kentton C. Grant	Rate:	RES-01 TOU
Title:	Vice President	Effective:	~~January 1, 2014~~Pending
District:	Entire Electric Service Area	Decision No:	~~74235~~Pending

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 102
Superseding:

Summer (May – October)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 – 400 kWh				
On-Peak	$0.030810	$0.101110	Varies	$0.131920
Off-Peak	$0.030810	$0.033900	Varies	$0.064710
Over 400 kWh				
On-Peak	$0.050810	$0.101110	Varies	$0.151920
Off-Peak	$0.050810	$0.033900	Varies	$0.084710

Winter (November – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 – 400 kWh				
On-Peak	$0.030810	$0.098960	Varies	$0.129770
Off-Peak	$0.030810	$0.033579	Varies	$0.064389
Over 400 kWh				
On-Peak	$0.050810	$0.098960	Varies	$0.149770
Off-Peak	$0.050810	$0.033579	Varies	$0.084389

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent~~-kWh~~ adjustment in accordance with ~~Rate-~~Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold~~. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

Calculation of Tiered (Block) Usage by TOU Period:

Step 1: Calculate percent usage by TOU period.

Step 2: Calculate the kWh usage by tier (block).

Step 3: Multiply percent usage by TOU period by kWh usage by tier to obtain tiered usage by TOU period.

Example: A Customer using 2,000 kWh in a month, with 20% on-peak usage and 80% off-peak usage will have 80 kWh in on-peak first tier and 320 kWh in on-peak second tier, and will have 320 kWh in off-peak first tier and 1280 kWh in off-peak second tier.

kWh	On-Peak	Off-Peak	Total
0 – 400 kWh	80	320	400
Over 400 kWh	320	1,280	1,600
Total	400	1,600	2,000

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 5:00 a.m. - 9:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

~~LOST FIXED COST RECOVERY (LFCR) - RIDER 8~~

~~For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.~~

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

~~Customer~~Basic Service Charge Components (Unbundled):

~~Standard~~	
Description	
Meter Services	$ 1.38~~2.11~~ per month
Meter Reading	$ 0.89~~2.39~~ per month
Billing & Collection	$ 6.01~~5.66~~ per month
Customer Delivery	$ 11.72~~1.34~~ per month
Total	$20.00~~11.50~~ per month

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh~~	
~~Description~~	
~~Meter Services~~	~~$ 2.11 per month~~
~~Meter Reading~~	~~$ 2.39 per month~~

~~Billing & Collection~~	~~$ 5.66 per month~~
~~Customer Delivery~~	~~$ 1.34 per month~~
~~LFCR~~	~~$ 2.50 per month~~
~~Total~~	~~$14.00 per month~~

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more~~	
~~Description~~	
~~Meter Services~~	~~$ 2.11 per month~~
~~Meter Reading~~	~~$ 2.39 per month~~
~~Billing & Collection~~	~~$ 5.66 per month~~
~~Customer Delivery~~	~~$ 1.34 per month~~
~~LFCR~~	~~$ 6.50 per month~~
~~Total~~	~~$18.00 per month~~

~~Energy Charge Components (per kWh) (Unbundled):~~

~~Summer (May – October)~~	~~On-Peak~~	~~Off-Peak~~
~~Local Delivery~~	~~$0.016321~~	~~$0.016321~~
~~Generation~~	~~$0.008325~~	~~$0.008325~~
~~Transmission~~	~~$0.005704~~	~~$0.005704~~

~~Power Supply Charge (per kWh):~~

~~Summer (May – October)~~	~~On-Peak~~	~~Off-Peak~~
~~Base Power Component~~	~~$0.129605~~	~~$0.039605~~
~~PPFAC~~	~~(See Rider -1 for current rate)~~	

~~Energy Charge Components (per kWh) (Unbundled):~~

~~Winter (November – April)~~	~~On-Peak~~	~~Off-Peak~~
~~Local Delivery~~	~~$0.016321~~	~~$0.016321~~
~~Generation Capacity~~	~~$0.008325~~	~~$0.008325~~
~~Transmission~~	~~$0.005704~~	~~$0.005704~~

~~Power Supply Charge (per kWh):~~

~~Winter (November – April)~~	~~On-Peak~~	~~Off-Peak~~
~~Base Power Component~~	~~$0.129605~~	~~$0.031385~~
~~PPFAC~~	~~(See Rider -1 for current rate)~~	

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	Rate
0 – 400 kWh	$0.009160
Over 400 kWh	$0.029160
Generation	$0.010980
Transmission	$0.010670

Power Supply Charges ~~(per kWh)~~:

Component	Rate
Base Power Supply Summer (May – October) On-Peak (per kWh)	$0.101110
Base Power Supply Summer (May – October) Off-Peak (per kWh)	$0.033900
Base Power Supply Winter (November – April) On-Peak (per kWh)	$0.098960
Base Power Supply Winter (November – April) Off-Peak (per kWh)	$0.033579
PPFAC (%) (see Rider-1 for current rate)	Varies

UniSource Energy SERVICES

UNS Electric, Inc.

Original Sheet No.: 103
Superseding:

Customer Assistance Residential Energy Support (CARES-F)

AVAILABILITY
~~Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.~~New Customers, including current Customers who move, are not eligible for service under this rate.

APPLICABILITY
To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to ~~individual motors exceeding 40 amperes at a rating of 230 volts or which will~~electrical equipment that causes excessive voltage fluctuations.

ELIGIBILITY
1. The UNS Electric account must be in the Customer's name applying for a CARES discount.
2. Applicant must be a UNS Electric residential Customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on UNS Electric's website at www.uesaz.com or contact a UNS Electric customer care representative.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF ~~CUSTOMER~~BASIC SERVICE AND ENERGY CHARGES

~~Customer Charges:~~
~~Standard~~
~~Customer~~Basic Service Charge ~~and minimum bill~~ $~~4.90~~9.00 per month

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option~~
~~CustomerBasic Service Charge with usage less than 2,000 kWh $ 7.40 per month~~
~~CustomerBasic Service Charge with usage of 2,000 kWh or more $11.40 per month~~

Energy Charges (per kWh):

	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 - ~~First~~ 400 kWh	$0.030810~~018973~~	$0.049260~~061700~~	Varies	$0.08007~~080673~~
Over 400~~All~~	$0.050810~~035400~~	$0.049260~~061700~~	Varies	$0.10007~~097100~~

Filed By:	Kentton C. Grant	Rate:	CARES-F
Title:	Vice President	Effective:	~~January 1, 2014~~Pending
District:	Entire Electric Service Area	Decision No:	~~74235~~Pending

~~Additional~~ kWh				

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent ~~kWh~~ adjustment in accordance with ~~Rate~~ Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold~~. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. – While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

MONTHLY CUSTOMER ASSISTANCE RESIDENTIAL ENERGY SUPPORT (CARES) DISCOUNT

The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the ~~Standard Customer~~Basic Service Charge, Delivery Charges, and Power Supply Charges:
0 – 300 kWh	30%
301 – 600 kWh	20%
601- 1,000 kWh	10%
Over 1,000 kWh	$~~8~~10.00

No CARES discount will be applied that will reduce the bill to less than zero.

~~LOST FIXED COST RECOVERY (LFCR) – RIDER 8~~

~~For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.~~

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

UniSource Energy SERVICES

UNS Electric, Inc.

Original Sheet No.: 103-2
Superseding:

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

~~Customer~~Basic Service Charge Components (Unbundled):

~~Standard~~	
Description	
Meter Services	$0.62~~0.90~~ per month
Meter Reading	$0.40~~1.02~~ per month
Billing & Collection	$2.71~~2.41~~ per month
Customer Delivery	$5.27~~0.57~~ per month
Total	$9.00~~4.90~~ per month

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh~~	
~~Description~~	
~~Meter Services~~	~~$0.90 per month~~
~~Meter Reading~~	~~$1.02 per month~~
~~Billing & Collection~~	~~$2.41 per month~~
~~Customer Delivery~~	~~$0.57 per month~~
~~LFCR~~	~~$2.50 per month~~
~~Total~~	~~$7.40 per month~~

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more~~	
~~Description~~	
~~Meter Services~~	~~$ 0.90 per month~~
~~Meter Reading~~	~~$ 1.02 per month~~
~~Billing & Collection~~	~~$ 2.41 per month~~
~~Customer Delivery~~	~~$ 0.57 per month~~
~~LFCR~~	~~$ 6.50 per month~~
~~Total~~	~~$11.40 per month~~

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	~~Rate~~
0 - ~~First~~ 400 kWh	$ 0.009160 ~~004255~~
Over 400~~All remaining~~ kWh	$ 0.029160 ~~020682~~
Generation Capacity	$ 0.010980~~008223~~
Transmission	$ 0.010670~~006495~~

Power Supply Charges ~~(per kWh)~~:

Component	~~Rate~~
Base Power Supply (per kWh)	$0.049260~~061700~~
PPFAC (%) (see Rider-1 for current rate)	Varies

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 104
Superseding:

Customer Assistance Residential Energy Support Low Income Medical Life Support Program (CARES-M-F)

AVAILABILITY

New Customers, including those who move are not eligible for service under this rate.

APPLICABILITY

To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

This CARES Low Income Medical Life Support Program is available to all qualified CARES residential customers who are medically life-support dependent and who meet the eligibility requirements.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to ~~individual motors exceeding 40 amperes at a rating of 230 volts or which will~~electrical equipment that causes excessive voltage fluctuations.

No CARES discount will be applied that will reduce the bill to less than zero.

ELIGIBILITY REQUIREMENTS

To be eligible for the CARES Low Income Medical Life Support Program, a Customer must meet the following requirements:

A. Require the use of medical equipment that is considered essential for sustaining life and is operated at the residence;
B. Submit to UNS Electric a statement signed by the attending physician that verifies that the customer is medically life-support dependent and states the type of essential medical equipment in use at the residence; and
C. Submit to UNS Electric verification by the physician to remain eligible for the program beyond two years.

The following equipment is representative of that which may be qualified as being essential under the program:

- Ventilator
- Oxygen concentrator
- Peritoneal Dialysis Cycler
- Hemo Dialysis Equipment
- Feeding Pump
- Infusion Pump
- Suction Machine
- Small Volume Nebulizer
- ~~Oximeter~~

CHARACTER OF SERVICE

The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE

A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF ~~CUSTOMER~~BASIC SERVICE AND ENERGY CHARGES

~~Customer Charges:~~
~~Standard~~
~~Customer~~Basic Service Charge ~~and minimum bill~~ $~~4.90~~9.00 per month

Filed By:	Kentton C. Grant	Rate:	CARES-M-F
Title:	Vice President	Effective:	~~January 1, 2014~~Pending
District:	Entire Electric Service Area	Decision No:	~~74235~~Pending

UniSourceEnergy
SERVICES

UNS Electric, Inc.

Original Sheet No.: 104
Superseding:

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option~~
~~CustomerBasic Service Charge with usage less than 2,000 kWh ———— $ 7.40 per month~~
~~CustomerBasic Service Charge with usage of 2,000 kWh or more ———— $11.40 per month~~

Filed By:	Kentton C. Grant	Rate:	CARES-M-F
Title:	Vice President	Effective:	~~January 1, 2014~~Pending
District:	Entire Electric Service Area	Decision No:	~~74235~~Pending

Energy Charges (per kWh):

	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 - ~~First~~ 400 kWh	$0.030810~~018973~~	$0.049260~~061700~~	Varies	$0.080070~~080673~~
Over 400~~All Additional~~ kWh	$0.050810~~035400~~	$0.049260~~061700~~	Varies	$0.100070~~097100~~

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent ~~kWh~~ adjustment in accordance with ~~Rate~~ Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold~~. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration -above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

CARES LOW INCOME MEDICAL LIFE SUPPORT PROGRAM DISCOUNT

The monthly bill for customers eligible under the CARES Low Income Medical Life Support Program shall be computed in accordance to the rates above including the following discount:

For Bills with Usage of:	Monthly Discount will be applied to the ~~Standard Customer~~Basic Service Charge, Delivery Charges, and Power Supply Charges:
0 – 600 kWh	30%
601 – 1,200 kWh	20%
1,201- 2,000 kWh	10%
Over 2,000 kWh	$108.00

~~LOST FIXED COST RECOVERY (LFCR) – RIDER 8~~

~~For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.~~

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 104-3
Superseding:

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

~~Customer~~Basic Service Charge Components (Unbundled):

~~Standard~~	
Description	
Meter Services	$0.62~~0.90~~ per month
Meter Reading	$0.40~~1.02~~ per month
Billing & Collection	$2.71~~2.41~~ per month
Customer Delivery	$5.27~~0.57~~ per month
Total	$9.00~~4.90~~ per month

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh~~	
~~Description~~	
~~Meter Services~~	~~$0.90 per month~~
~~Meter Reading~~	~~$1.02 per month~~
~~Billing & Collection~~	~~$2.41 per month~~
~~Customer Delivery~~	~~$0.57 per month~~
~~LFCR~~	~~$2.50 per month~~
~~Total~~	~~$7.40 per month~~

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more~~	
~~Description~~	
~~Meter Services~~	~~$ 0.90 per month~~
~~Meter Reading~~	~~$ 1.02 per month~~
~~Billing & Collection~~	~~$ 2.41 per month~~
~~Customer Delivery~~	~~$ 0.57 per month~~
~~LFCR~~	~~$ 6.50 per month~~
~~Total~~	~~$11.40 per month~~

UniSource Energy SERVICES

UNS Electric, Inc.

Original Sheet No.: 104-4
Superseding:

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	~~Rate~~
0 - ~~First~~ 400 kWh	$0.009160~~0.004255~~
Over 400 ~~All remaining~~ kWh	$0.029160~~0.020682~~
Generation Capacity	$0.010980~~0.008223~~
Transmission	$0.010670~~0.006495~~

Power Supply Charges ~~(per kWh)~~:

Component	~~Rate~~
Base Power Supply (per kWh)	$0.049260~~0.061700~~
PPFAC (%) (see Rider-1 for current rate)	Varies

Filed By: Kentton C. Grant
Title: Vice President
District: Entire Electric Service Area

Rate: CARES-M-F
Effective: ~~January 1, 2014~~Pending
Decision No: ~~74235~~Pending

Residential Service Time-of-Use Super Peak (RES-01 TOU SuperPeak)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to ~~individual motors exceeding 40 amperes at a rating of 230 volts or which will~~electrical equipment that causes excessive voltage fluctuations.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

Service under this rate will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF ~~CUSTOMER~~BASIC SERVICE AND ENERGY CHARGES

~~Customer Charges:~~
~~Standard~~
~~Customer~~Basic Service Charge ~~and minimum bill~~ $~~11.50~~20.00 per month

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option~~
~~CustomerBasic Service Charge with usage less than 2,000 kWh $14.00 per month~~
~~CustomerBasic Service Charge with usage of 2,000 kWh or more $18.00 per month~~
Energy Charges (per kWh):

Summer (May – October)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 – 400 kWh				
On-Peak	$0.030810	$0.149700	Varies	$0.180510
Off-Peak	$0.030810	$0.038250	Varies	$0.069060
Over 400 kWh				
On-Peak	$0.050810	$0.149700	Varies	$0.200510
Off-Peak	$0.050810	$0.038250	Varies	$0.089060

~~Energy Charges (per kWh):~~

Winter (November – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 – 400 kWh				
On-Peak	$0.030810	$0.149700	Varies	$0.180510
Off-Peak	$0.030810	$0.038250	Varies	$0.069060
Over 400 kWh				
On-Peak	$0.050810	$0.149700	Varies	$0.200510
Off-Peak	$0.050810	$0.038250	Varies	$0.089060

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent ~~kWh~~ adjustment in accordance with ~~Rate~~ Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold~~. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

Calculation of Tiered (Block) Usage by TOU Period:

Step 1: Calculate percent usage by TOU period.

Step 2: Calculate the kWh usage by tier (block).

Step 3: Multiply percent usage by TOU period by kWh usage by tier to obtain tiered usage by TOU period.

Example: A Customer using 2,000 kWh in a month, with 20% on-peak usage and 80% off-peak usage will have 80 kWh in on-peak first tier and 320 kWh in on-peak second tier, and will have 320 kWh in off-peak first tier and 1280 kWh in off-peak second tier.

kWh	On-Peak	Off-Peak	Total
0 – 400 kWh	80	320	400
Over 400 kWh	320	1,280	1,600
Total	400	1,600	2,000

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 5:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak period is 5:00 p.m. - 8:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

~~LOST FIXED COST RECOVERY (LFCR) – RIDER 8~~

~~For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.~~

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

UniSource Energy SERVICES

UNS Electric, Inc.

Original Sheet No.: 105-5
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

~~Customer~~Basic Service Charge Components (Unbundled):

~~Standard~~	
Description	
Meter Services	$ 1.38~~2.11~~ per month
Meter Reading	$ 0.89~~2.39~~ per month
Billing & Collection	$ 6.01~~5.66~~ per month
Customer Delivery	$ 11.72~~1.34~~ per month
Total	$20.00~~11.50~~ per month

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option – usage less than 2,000 kWh~~	
~~Description~~	
~~Meter Services~~	~~$ 2.11 per month~~
~~Meter Reading~~	~~$ 2.39 per month~~
~~Billing & Collection~~	~~$ 5.66 per month~~
~~Customer Delivery~~	~~$ 1.34 per month~~
~~LFCR~~	~~$ 2.50 per month~~
~~Total~~	~~$14.00 per month~~

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option – usage of 2,000 kWh or more~~	
~~Description~~	
~~Meter Services~~	~~$ 2.11 per month~~
~~Meter Reading~~	~~$ 2.39 per month~~
~~Billing & Collection~~	~~$ 5.66 per month~~
~~Customer Delivery~~	~~$ 1.34 per month~~
~~LFCR~~	~~$ 6.50 per month~~
~~Total~~	~~$18.00 per month~~

~~Energy Charge Components (per kWh) (Unbundled):~~

~~All Months~~	~~On-Peak~~	~~Off-Peak~~
~~Local Delivery 1st 400~~	~~$0.0110~~	~~$0.0110~~
~~Local Delivery all additional~~	~~$0.0210~~	~~$0.0210~~

~~Generation Capacity~~	~~$0.0083~~	~~$0.0083~~
~~Transmission~~	~~$0.0057~~	~~$0.0057~~

~~Power Supply Charge (per kWh):~~

	~~On-Peak~~	~~Off-Peak~~
~~Summer (May – October)~~	~~$0.1700~~	~~$0.0397~~
~~Winter (November – April)~~	~~$0.1500~~	~~$0.0387~~
~~PPFAC~~	~~(See Rider -1 for current rate)~~	

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	Rate
0 – 400 kWh	$0.009160
Over 400 kWh	$0.029160
Generation	$0.010980
Transmission	$0.010670

Power Supply Charges ~~(per kWh)~~:

Component	Rate
Base Power Supply Summer (May – October) On-Peak (per kWh)	$0.149700
Base Power Supply Summer (May – October) Off-Peak (per kWh)	$0.038250
Base Power Supply Winter (November – April) On-Peak (per kWh)	$0.149700
Base Power Supply Winter (November – April) Off-Peak (per kWh)	$0.038250
PPFAC (%) (see Rider-1 for current rate)	Varies

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 201
Superseding:

Small General Service (SGS-10)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rates, when all energy is supplied at one point of delivery and through one metered service.

The supply of electric service under a residential rate to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the electricity used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters. Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises must be classified as non-residential and the appropriate general service rate will be applied.

~~Only available to Customers with imputed demand less than 500 KW. However, service is available for Customer-owned, operated, and maintained area, street, or stadium lighting, and for firm irrigation service with a maximum monthly demand less than 25 kW.~~

Not applicable to resale, breakdown, ~~temporary,~~ standby, or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

In the event a Customer~~s~~ meets or exceeds ~~using~~ 12,000 ~~or more~~ kWh in two consecutive months ~~under the Small General Service tariff henceforth shall receive service under~~ the Customer will be moved to the ~~Large~~Medium General Service tariff.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF ~~CUSTOMER~~BASIC SERVICE AND ENERGY CHARGES

~~Customer~~Basic Service Charge: $~~14.50~~30.00 per month

Energy Charges (per kWh):

	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
0 - 400 kWh	$0.039497~~030176~~	$0.048610~~058241~~	Varies	$0.088107~~088417~~
401 – 7,500 kWh	$0.049497~~041042~~	$0.048610~~058241~~	Varies	$0.098107~~099283~~

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 201
Superseding:

Over 7,500 kwh	$0.086950~~076042~~	$0.048610~~058241~~	Varies	$0.13556~~134283~~

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent ~~kWh~~ adjustment in accordance with ~~Rate~~ Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold~~. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 201-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

~~Customer~~Basic Service Charge Components (Unbundled):

Description	~~Customer~~Basic Service Charge
Meter Services	$ 1.18~~2.37~~ per month
Meter Reading	$ 11.51~~4.60~~ per month
Billing & Collection	$ 5.17~~6.35~~ per month
Customer Delivery	$ 12.14~~1.18~~ per month
Total	$ 30.00~~14.50~~ per month

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	Rate
0 – 400 kWh	$0.018127~~013662~~
401 – 7,500 kWh	$0.028127~~024528~~
Over 7,500 kWh	$0.065580~~059528~~
Generation Capacity	$0.010840~~010400~~
Transmission	$0.010530~~006114~~

Power Supply Charges ~~(per kWh)~~:

Component	Rate
Base Power Supply (per kWh)	$0.048610~~058241~~
PPFAC (%) (see Rider-1 for current rate)	Varies

Small General Service Time-of-Use (SGS-10 TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific Rates, when all energy is supplied at one point of delivery and through one metered service.

The supply of electric service under a residential Rate to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the electricity used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters. Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises must be classified as non-residential and the appropriate general service rate will be applied.

~~Only available to Customers with imputed demand less than 500 kW; however, service is available for Customer-owned, operated, and maintained area, street, or stadium lighting, and for firm irrigation service with a maximum monthly demand less than 25 kW.~~

Service under this rate will commence when the appropriate meter has been installed.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

In the event a Customer meets or exceeds 12,000 kWh in two consecutive months the Customer will be moved to the Medium General Service Time-of-Use tariff.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

UniSource Energy SERVICES

UNS Electric, Inc.

Original Sheet No.: 202-1
Superseding:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF ~~CUSTOMER~~BASIC SERVICE AND ENERGY CHARGES

~~Customer~~Basic Service Charge: $~~16.50~~30.00 per month

Energy Charges (per kWh):

Summer (May – October)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 - 400 kWh				
On-Peak	$0.039497~~030176~~	$0.126510~~129605~~	Varies	$0.166007~~159781~~
Off-Peak	$0.039497~~030176~~	$0.033010~~039605~~	Varies	$0.072507~~069781~~
401 – 7,500 kWh				
On-Peak	$0.049497~~043176~~	$0.126510~~129605~~	Varies	$0.176007~~172781~~
Off-Peak	$0.049497~~043176~~	$0.033010~~039605~~	Varies	$0.082507~~082781~~
Over 7,500 kWh				
On-Peak	$0.086950~~076042~~	$0.126510~~129605~~	Varies	$0.213460~~205647~~
Off-Peak	$0.086950~~076042~~	$0.033010~~039605~~	Varies	$0.119960~~115647~~

Winter (November – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 - 400 kWh				
On-Peak	$0.039497~~03030176~~	$0.108510~~129605~~	Varies	$0.148007~~159781~~
Off-Peak	$0.039497~~03030176~~	$0.032910~~031385~~	Varies	$0.072407~~061561~~
401 – 7,500 kWh				
On-Peak	$0.049497~~0043176~~	$0.108510~~129605~~	Varies	$0.158007~~172781~~
Off-Peak	$0.049497~~0043176~~	$0.032910~~031385~~	Varies	$0.082407~~074561~~
Over 7,500 kWh				
On-Peak	$0.086950~~076042~~	$0.108510~~129605~~	Varies	$0.195460~~205647~~
Off-Peak	$0.086950~~076042~~	$0.032910~~031385~~	Varies	$0.119860~~107427~~

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent ~~kWh~~ adjustment in accordance with ~~Rate~~ Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold~~. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month

Filed By:	Kentton C. Grant	Rate:	SGS-10 TOU
Title:	Vice President	Effective:	~~January 1, 2014~~Pending
District:	Entire Electric Service Area	Decision No.:	~~74235~~Pending

Calculation of Tiered (Block) Usage by TOU Period:

Step 1: Calculate percent usage by TOU period.

Step 2: Calculate the kWh usage by tier (block).

Step 3: Multiply percent usage by TOU period by kWh usage by tier to obtain tiered usage by TOU period.

Example: A Customer using 10,000 kWh in a month, with 20% on-peak usage and 80% off-peak usage will have 80 kWh in on-peak first tier, 1,420 kWh in on-peak second tier and 500 kWh in on-peak third tier and 320 kWh in off-peak first tier, 5,680 kWh in off-peak second tier and 2,000 kWh in off-peak third tier.

kWh	On-Peak	Off-Peak	Total
0 – 400 kWh	80	320	400
401 – 7,500 kWh	1,420	5,680	7,100
Over 7,500 kWh	500	2,000	2,500
Total	2,000	8,000	10,000

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 5:00 a.m. - 9:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 202-3
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

~~Customer~~Basic Service Charge Components (Unbundled):

Description	~~CustomerBasic Service Charge~~
Meter Services	$ 1.18~~2.69~~ per month
Meter Reading	$ 11.51~~5.24~~ per month
Billing & Collection	$ 5.17~~7.23~~ per month
Customer Delivery	$ 12.14~~1.34~~ per month
Total	$ 30.00~~16.50~~ per month

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 202-4
Superseding:

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	Rate
0 – 400 kWh	$0.018127~~013662~~
401 – 7,500 kWh	$0.028127~~026662~~
Over 7,500 kWh	$0.065580~~059528~~
Generation Capacity	$0.01084~~010400~~
Transmission	$0.01053~~006114~~

Power Supply Charges ~~(per kWh)~~:

Component	Rate
Base Power Supply Summer (May – October) On-Peak (per kWh)	$0.126510~~129605~~
Base Power Supply Summer (May – October) Off-Peak (per kWh)	$0.033010~~039605~~
Base Power Supply Winter (November – April) On-Peak (per kWh)	$0.108510~~129605~~
Base Power Supply Winter (November – April) Off-Peak (per kWh)	$0.032910~~031385~~
PPFAC (%) (see Rider -1 for current rate)	Varies

Time-of-Use for Small General Service Schools (SGS-10 TOU-S)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all private and public schools (K-12) unless otherwise addressed by specific Rates, when all energy is supplied at one point of delivery and through one metered service.

Service under this Rate will commence when the appropriate meter has been installed.

Only available to Customers with imputed demand less than 500 KW.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge: $16.50 per month

Energy Charges (per kWh):

Summer (May – October)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 - 400 kWh				
On-Peak	$0.030176	$0.137405	Varies	$0.167581
Off-Peak	$0.030176	$0.047405	Varies	$0.077581
401 – 7,500 kWh				
On-Peak	$0.043176	$0.137405	Varies	$0.180581
Off-Peak	$0.043176	$0.047405	Varies	$0.090581
Over 7,500 kWh				
On-Peak	$0.076042	$0.137405	Varies	$0.213447
Off-Peak	$0.076042	$0.047405	Varies	$0.123447

Winter (November – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 - 400 kWh				
On-Peak	$0.030176	$0.137405	Varies	$0.167581
Off-Peak	$0.030176	$0.039185	Varies	$0.069361
401 – 7,500 kWh				
On-Peak	$0.043176	$0.137405	Varies	$0.180581
Off-Peak	$0.043176	$0.039185	Varies	$0.082361
Over 7,500 kWh				
On-Peak	$0.076042	$0.137405	Varies	$0.213447
Off-Peak	$0.076042	$0.039185	Varies	$0.115227

1. Delivery Services-Energy is a bundled charge that includes: Transmission, Sub-transmission, Local Delivery Energy and Production not included in Power Supply.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

TIME-OF-USE PERIODS

The Summer On-Peak period is 3:00 p.m. to 7:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 5:00 a.m. - 9:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this Rate.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Customer Charge Components (Unbundled):

Description	Customer Charge
Meter Services	$ 2.69 per month
Meter Reading	$ 5.24 per month
Billing & Collection	$ 7.23 per month
Customer Delivery	$ 1.34 per month
Total	$16.50 per month

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	Rate
0 – 400 kWh	$0.013662
401 – 7,500 kWh	$0.026662
Over 7,500 kWh	$0.059528
Generation Capacity	$0.010400
Transmission	$0.006114

Power Supply Charges (per kWh):

Component	Rate
Base Power Supply Summer (May – October) On-Peak	$0.137405
Base Power Supply Summer (May – October) Off-Peak	$0.047405
Base Power Supply Winter (November – April) On-Peak	$0.137405
Base Power Supply Winter (November – April) Off-Peak	$0.039185
PPFAC (see Rider -1 for current rate)	Varies

Large General Service (LGS)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, temporary, standby or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at a voltage of less than 69 kV~~one standard nominal voltage as mutually agreed~~ and subject to availability at point of delivery.

Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF ~~CUSTOMER~~BASIC SERVICE, DEMAND AND ENERGY CHARGES

~~Customer~~Basic Service Charge: $300.00~~50.00~~ per month

Demand Charge: $12.96~~12.81~~ per kW

Energy Charge (per kWh):

	Delivery Services-Energy~~1~~	Power Supply Charges 1~~2~~		Total 2~~3~~
		Base Power	PPFAC 1~~2~~	
All kWh	$0.005400~~005470~~	$0.048400~~056603~~	Varies	$0.053800~~062073~~

~~1. Delivery Services Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.~~

~~2.~~1. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent~~-kWh~~ adjustment in accordance with ~~Rate~~ Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold~~. Please see Rider-1 for current rate.

~~3.~~2. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

BILLING DEMAND
The monthly billing demand shall be the greater~~st~~ of the following:

1. The greatest measured ~~maximum~~ 15 minute interval ~~measured~~ demand read of the meter during all hours of ~~in~~ the billing period~~month~~;
2. 75% of the ~~maximum~~greatest demand used for billing purposes in the preceding 11 months; or
3. The contract capacity or ~~demand amount, not to be less than 20~~450 kW, whichever is greater.

The Company reserves the right to require a Customer to install equipment to maintain an acceptable power factor at the Customer's expense.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 22004-2
Superseding: ____________

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

~~Customer~~Basic Service Charge Components (Unbundled):

Description	~~Customer~~Basic Service Charge
Meter Services	$ 5.01~~7.28~~ per month
Meter Reading	$ 31.32~~18.59~~ per month
Billing & Collection	$ 22.15~~19.59~~ per month
Customer Delivery	$ 241.52~~4.54~~ per month
Total	$ 300.00~~50.00~~ per month

Demand Charges (per kW) (Unbundled):

Component	Rate
Demand Delivery	$ 8.29~~7.64~~
Generation Capacity	$ 2.37~~3.09~~
Transmission	$ 2.30~~2.08~~

Energy Charge Components (per kWh) (Unbundled):

	Rate
Local Delivery	$0.005400~~2909~~
~~Generation~~	~~$0.002394~~
~~Transmission~~	~~$0.000167~~

Power Supply Charges ~~(per kWh)~~:

Component	Rate
Base Power Supply (per kWh)	$0.048400~~056603~~
PPFAC (%) (see Rider-1 for current rate)	Varies

Filed By:	Kentton C. Grant	Rate:	LGS
Title:	Vice President	Effective:	~~January 1, 2014~~Pending
District:	Entire Electric Service Area	Decision No:	~~74235~~Pending

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 221~~05~~
Superseding:

Large General Service Time-of-Use (LGS TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service.

Service under this rate will commence when the appropriate meter has been installed.

-Not applicable to resale, breakdown, temporary, standby or auxiliary service.

-Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at a voltage of less than 69 kV ~~one standard nominal voltage as mutually agreed~~ and subject to availability at point of delivery.

Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF ~~CUSTOMER~~BASIC SERVICE, DEMAND AND ENERGY CHARGES

~~Customer~~Basic Service Charge: $~~52.00~~300.00 per month

Demand Charge: $~~12.81~~12.96 per kW

Energy Charges (per kWh):

Summer (May – October)	Delivery Services-Energy~~[1]~~	Power Supply Charges[1~~2~~] Base Power	PPFAC[1~~2~~]	Total[2~~3~~]
On-Peak	$0.005400~~005470~~	$0.145510~~114886~~	Varies	$0.150910~~120356~~
Off-Peak	$0.005400~~005470~~	$0.034510~~039886~~	Varies	$0.039910~~045356~~

Winter (November – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
On-Peak	$0.005400~~005470~~	$0.124510~~114886~~	Varies	$0.129910~~120356~~
Off-Peak	$0.005400~~005470~~	$0.032910~~026168~~	Varies	$0.038310~~031638~~

Filed By: Kentton C. Grant
Title: Vice President
District: Entire Electric Service Area

Rate: LGS-TOU
Effective: ~~January 1, 2014~~Pending
Decision No: ~~74235~~Pending

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 221~~05~~
Superseding:

~~1.~~ 1. ~~Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.~~

~~2~~1. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent ~~kWh~~ adjustment in accordance with ~~Rate~~ Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold~~. Please see Rider-1 for current rate.

~~3~~2. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

Filed By:	Kentton C. Grant	Rate:	LGS-TOU
Title:	Vice President	Effective:	~~January 1, 2014~~Pending
District:	Entire Electric Service Area	Decision No:	~~74235~~Pending

BILLING DEMAND
The monthly billing demand shall be the greatest of the following:

1. The greatest measured~~maximum~~ 15 minute interval~~measured~~ demand read of the meter during all hours of~~in~~ the billing period~~month~~;
2. 75% of the ~~maximum~~greatest demand used for billing purposes in the preceding 11 months; or
3. The contract capacity or ~~demand amount, not to be less than 20~~450 kW, whichever is greater.

The Company reserves the right to require a Customer to install equipment to maintain an acceptable power factor at the Customer's expense.

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 5:00 a.m. - 9:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 221~~05~~-3
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

~~Customer~~Basic Service Charge Components (Unbundled):

Description	~~CustomerBasic Service Charge~~
Meter Services	$ 5.01~~7.57~~ per month
Meter Reading	$ 31.32~~19.33~~ per month
Billing & Collection	$ 22.15~~20.38~~ per month
Customer Delivery	$~~–~~241.52~~4.72~~ -per month
Total	$-300.00~~52.00~~ -per month

Demand Charge (per kW) (Unbundled):

Component	~~Rate~~
Demand Delivery	$ 8.29~~7.64~~
Generation Capacity	$ 2.37~~3.09~~
Transmission	$ 2.30~~2.08~~

Energy Charge Components (per kWh) (Unbundled):

	~~Rate~~
Local Delivery	$0.005400~~2909~~
~~Generation~~	~~$0.002394~~
~~Transmission~~	~~$0.000167~~

Power Supply Charges ~~(per kWh)~~:

Component	~~Rate~~
Base Power Supply Summer (May – October) On-Peak (per kWh)	$0.145510~~114886~~
Base Power Supply Summer (May – October) Off-Peak (per kWh)	$0.034510~~039886~~
Base Power Supply Winter (November – April) On-Peak (per kWh)	$0.124510~~114886~~
Base Power Supply Winter (November – April) Off-Peak (per kWh)	$0.032910~~026168~~
PPFAC (%) (see Rider -1 for current rate)	Varies

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 222~~06~~
Superseding: ____________

Time-of-Use for Large General Service Schools (LGS-TOU-S)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all private and public schools (K-12) unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service.

Service under this rate will commence when the appropriate meter has been installed.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at a voltage of less than 69 kV ~~one standard nominal voltage as mutually agreed~~ and subject to availability at point of delivery.

Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF ~~CUSTOMER~~BASIC SERVICE, DEMAND AND ENERGY CHARGES

~~Customer~~Basic Service Charge: $~~52.00~~300.00 per month

Demand Charge: $12.96~~12.81~~ per kW

Energy Charges (per kWh):

Summer (May – October)	Delivery Services-Energy[4]	Power Supply Charges[1~~2~~] Base Power	PPFAC[1~~2~~]	Total[2~~3~~]
On-Peak	$0.005400~~005470~~	$0.150210~~120586~~	Varies	$0.155610~~126056~~
Off-Peak	$0.005400~~005470~~	$0.039210~~045586~~	Varies	$0.044610~~051056~~

Winter (November – April)	Delivery Services-Energy[4]	Power Supply Charges[1~~2~~] Base Power	PPFAC[1~~2~~]	Total[2~~3~~]
On-Peak	$0.005400~~005470~~	$0.129210~~120586~~	Varies	$0.134610~~126056~~
Off-Peak	$0.005400~~005470~~	$0.037610~~031868~~	Varies	$0.043010~~037338~~

~~1. Delivery Services-Energy is a bundled charge that includes: Transmission, Sub-transmission, Local Delivery Energy and Production not included in Power Supply.~~

1~~2~~. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent~~-kWh~~ adjustment in accordance with ~~Rate~~ Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold~~. Please see Rider-1 for current rate.

2~~3~~. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month

BILLING DEMAND

The monthly billing demand shall be the greate~~st~~r of the following:

1. The greatest measured~~maximum~~ 15 minute interval ~~measured~~ demand read of the meter during all hours of~~in~~ the billing period~~month~~;
2. 75% of the ~~maximum~~greatest demand used for billing purposes in the preceding 11 months; or
3. The contract capacity or ~~demand amount, not to be less than 20~~450 kW, whichever is greater.

The Company reserves the right to require a Customer to install equipment to maintain an acceptable power factor at the Customer's expense.

TIME-OF-USE PERIODS

The Summer On-Peak period is 3:00 p.m. to 7:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 5:00 a.m. - 9:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

UniSource Energy SERVICES

UNS Electric, Inc.

Original Sheet No.: 222~~06~~-2
Superseding: ____________

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

~~Customer~~Basic Service Charge Components (Unbundled):

Description	~~CustomerBasic Service Charge~~
Meter Services	$ 5.01~~7.57~~ per month
Meter Reading	$ 31.32~~19.33~~ per month
Billing & Collection	$ 22.15~~20.38~~ per month
Customer Delivery	$~~—~~241.52~~4.72~~ per month
Total	$~~-~~300.00~~52.00~~ per month

Demand Charge (per kW) (Unbundled):

Component	~~Rate~~
Demand Delivery	$~~-~~8.29~~7.64~~
Generation Capacity	$~~-~~2.37~~3.09~~
Transmission	$~~-~~2.30~~08~~

Energy Charge Components (per kWh) (Unbundled):

	~~Rate~~
Local Delivery	$0.005400~~2909~~
~~Generation~~	~~$0.002394~~
~~Transmission~~	~~$0.000167~~

Power Supply Charges ~~(per kWh)~~:

Component	~~Rate~~
Base Power Supply Summer (May – October) On-Peak (per kWh)	$0.150210~~120586~~
Base Power Supply Summer (May – October) Off-Peak (per kWh)	$0.039210~~045586~~
Base Power Supply Winter (November – April) On-Peak (per kWh)	$0.129210~~120586~~
Base Power Supply Winter (November – April) Off-Peak (per kWh)	$0.037610~~31868~~
PPFAC (%) (see Rider -1 for current rate)	Varies

Large Power Service (LPS)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, temporary, standby or auxiliary service.

CHARACTER OF SERVICE
The service shall be three-phase, 60 Hertz, and at the Company's standard transmission ~~or distribution~~ voltages that are available within the vicinity of the Customer's premises.

Primary metering at primary voltages greater than or equal to 69 kV shall be required for service under this tariff. ~~new installations with service requirements in excess of 2,500 kW.~~

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF ~~CUSTOMER~~BASIC SERVICE, DEMAND AND ENERGY CHARGES

~~Customer~~Basic Service Charge: $1,200.00 per month

~~Demand Charges:~~
~~Demand Charge (<69 kV Service) $22.00 per kW per month~~
Demand Charge ~~(≥69 kV Service)~~:
$12.48~~17.00~~ per kW ~~per month~~

Energy Charge (per kWh):

	Delivery Services-Energy~~[1]~~	Power Supply Charges[1]~~[2]~~ Base Power	PPFAC[1]~~[2]~~	Total[2]~~[3]~~
All kWh	$0.000520~~000462~~	$0.048410~~041880~~	Varies	$0.048930~~042342~~

~~1. Delivery Services Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.~~

~~2~~1. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent ~~kWh~~ adjustment in accordance with ~~Rate~~ Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold~~. Please see Rider-1 for current rate.

~~3~~2. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

~~A credit of three percent (3%) will be applied to the demand charge if the Customer receives Distribution Service at primary voltage.~~

~~In the event a Customer achieves permanent, verifiable demand reduction through involvement in UNS Electric's Demand Side Management (DSM) programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.~~

BILLING DEMAND

The monthly billing demand shall be the greater~~higher~~ of the following:

1. T~~t~~he greatest~~highest~~ measured 15~~fifteen-~~ minute interval ~~integrated reading of the~~ demand read of the meter during all hours of the billing period;
2. T~~t~~he greatest~~highest~~ demand metered ~~during~~ in the preceding eleven (11) months; or
3. T~~t~~he contract capacity or 500 kW, whichever is greater~~higher~~.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than ninety-five percent (95%), an adjustment shall be applied to the bill as follows:

POWER FACTOR ADJUSTMENT

(Maximum Demand / (.05 + PF)) - Maximum Demand) x Demand Charge Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

POWER FACTOR

1. The Company may require the Customer by written notice to either maintain a specified minimum lagging power factor or the Company may after thirty (30) days install power factor corrective equipment and bill the Customer for the total costs of this equipment and installation.
2. In the case of apparatus and devices having low power factor, now in service, which may hereafter be replaced, and all similar equipment hereafter installed or replaced, served under general commercial schedules, the Company may require the Customer to provide, at the Customer's own expense, power factor corrective equipment to increase the power factor of any such devices to not less than ninety (90) percent.
3. If the Customer installs and owns the capacitors needed to supply his reactive power requirements, then the Customer must equip them with suitable disconnecting switches, so installed that the capacitors will be disconnected from the Company's lines whenever the Customer's load is disconnected from the Company's facilities.
4. Gaseous tube installations totaling more than one thousand (1,000) volt-amperes must be equipped with capacitors of sufficient rating to maintain a minimum of ninety percent (90%) lagging power factor.
5. Company installation and removal of metering equipment to measure power factor will be at the discretion of the Company.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 301-2
Superseding:

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the Customer or pursuant to the Customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

OTHER PROVISIONS
Service hereunder shall remain in full force and in effect until terminated by the Customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the Customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

~~Customer~~Basic Service Charge Components (Unbundled):

Description	~~CustomerBasic Service Charge~~
Meter Services	$ 101.86~~184.69~~ per month
Meter Reading	$ 145.57~~364.17~~ per month
Billing & Collection	$ 451.63~~498.49~~ per month
Customer Delivery	$ 500.94~~152.65~~ per month
Total	$ 1,200.00 per month

~~Demand Charge <69kW (Unbundled):~~

~~Component~~	~~Rate~~
~~Delivery Services- All kW~~	
~~Local Delivery~~	~~$ 17.50~~
~~Generation~~	~~$ 2.07~~
~~Transmission~~	~~$ 2.43~~

Demand Charge (per kW) ~~>69kW~~ (Unbundled):

Component	~~Rate~~
Delivery Services- All kW	
Local Delivery	$ 5.22~~12.73~~
Generation Capacity	$ 3.68~~2.07~~
Transmission	$ 3.58~~2.20~~

Filed By:	Kentton C. Grant	Rate:	LPS
Title:	Vice President	Effective:	~~January 1, 2014~~Pending
District:	Entire Electric Service Area	Decision No:	~~74235~~Pending

Energy Charge Components (per kWh) (Unbundled):

	~~Rate~~
Local Delivery	$0.000520~~0343~~
~~Generation~~	~~$0.000100~~
~~Transmission~~	~~$0.000019~~

Power Supply Charges ~~(per kWh)~~:

Component	~~Rate~~
Base Power Supply (per kWh)	$0.048410~~041880~~
PPFAC (%) (see Rider-1 for current rate)	Varies

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 302
Superseding:

Large Power Service Time-of-Use (LPS-TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, temporary, standby or auxiliary service.

CHARACTER OF SERVICE
The service shall be three-phase, 60 Hertz, and at the Company's standard transmission ~~or distribution~~ voltages that are available within the vicinity of the Customer's premises.

Primary metering at primary voltages greater than or equal to 69kV shall be required for service under this tariff. ~~new installations with service requirements in excess of 2,500 kW.~~

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF ~~CUSTOMER~~BASIC SERVICE, DEMAND AND ENERGY CHARGES

~~Customer~~Basic Service Charge:	$1,200.00 per month
~~Demand Charges:~~	
~~Demand Charge (<69 kV Service)~~	~~$22.00 per kW per month~~
Demand Charge ~~(≥69 kV Service)~~	$~~17.00~~12.48 per kW per month

Energy Charges (per kWh):

Summer (May – October)	Delivery Services-Energy~~[1]~~	Power Supply Charges[1]~~[2]~~ Base Power	PPFAC[1]~~[2]~~	Total[2]~~[3]~~
On-Peak	$0.000520~~000462~~	$0.122510~~123580~~	Varies	$0.123030~~124042~~
Off-Peak	$0.000520~~000462~~	$0.032110~~024716~~	Varies	$0.032630~~025178~~

Winter (November – April)	Delivery Services-Energy~~[1]~~	Power Supply Charges[1]~~[2]~~ Base Power	PPFAC[1]~~[2]~~	Total[2]~~[3]~~
On-Peak	$0.000520~~000462~~	$0.092110~~093880~~	Varies	$0.092630~~094342~~
Off-Peak	$0.000520~~000462~~	$0.030910~~022105~~	Varies	$0.031430~~022567~~

~~1. Delivery Services Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.~~

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 302-1
Superseding:

~~2~~1. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent~~-kWh~~ adjustment in accordance with ~~Rate-~~Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold~~. Please see Rider-1 for current rate.

~~3~~2. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

~~A credit of three percent (3%) will be applied to the demand charge if the Customer receives Distribution Service at primary voltage.~~

~~In the event a Customer achieves permanent, verifiable demand reduction through involvement in UNS Electric's Demand-Side Management (DSM) programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.~~

BILLING DEMAND

The monthly billing demand shall be the greater~~higher~~ of the following:

1. T~~t~~he ~~highest~~greatest measured 15~~fifteen-~~ minute interval ~~integrated reading of the~~ demand read of the meter during the on-peak hours of the billing period;
2. O~~o~~ne-half of the greatest~~highest~~ measured 15~~fifteen~~ minute interval demand ~~integrated reading of the demand~~read of the meter during the off-peak hours of the billing period;
3. T~~t~~he greater~~higher~~ of (1) or (2) above during the preceding ~~eleven (~~11~~)~~ months; or
4. T~~t~~he contract capacity or 500 kW, whichever is greater~~higher~~.

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 12:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than ninety-five percent (95%), an adjustment shall be applied to the bill as follows:

POWER FACTOR ADJUSTMENT

(Maximum Demand / (.05 + PF)) - Maximum Demand) x Demand Charge Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

POWER FACTOR

1. The Company may require the Customer by written notice to either maintain a specified minimum lagging power factor or the Company may after thirty (30) days install power factor corrective equipment and bill the Customer for the total costs of this equipment and installation.

2. In the case of apparatus and devices having low power factor, now in service, which may hereafter be replaced, and all similar equipment hereafter installed or replaced, served under general commercial schedules, the Company may require the Customer to provide, at the Customer's own expense, power factor corrective equipment to increase the power factor of any such devices to not less than ninety (90) percent.
3. If the Customer installs and owns the capacitors needed to supply his reactive power requirements, then the Customer must equip them with suitable disconnecting switches, so installed that the capacitors will be disconnected from the Company's lines whenever the Customer's load is disconnected from the Company's facilities.
4. Gaseous tube installations totaling more than one thousand (1,000) volt-amperes must be equipped with capacitors of sufficient rating to maintain a minimum of ninety percent (90%) lagging power factor.
5. Company installation and removal of metering equipment to measure power factor will be at the discretion of the Company.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the Customer or pursuant to the Customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

OTHER PROVISIONS

Service hereunder shall remain in full force and in effect until terminated by the Customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the Customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

~~Customer~~Basic Service Charge Components (Unbundled):

Description	~~CustomerBasic Service Charge~~
Meter Services	$ 101.86~~184.69~~ per month
Meter Reading	$ 145.57~~364.17~~ per month
Billing & Collection	$ 451.63~~498.49~~ per month
Customer Delivery	$ 500.94~~152.65~~ per month
Total	$1,200.00 per month

~~Demand Charge <69kV (Unbundled):~~

~~Component~~	~~Rate~~
~~Delivery Services- All kW~~	
~~Local Delivery~~	~~$ 17.50 per kW~~
~~Generation Capacity~~	~~$ 2.07 per kW~~
~~Transmission~~	~~$ 2.43 per kW~~

Demand Charge (per kW) ~~≥69kV~~ (Unbundled):

Component	~~Rate~~
Delivery Services- All kW	
Local Delivery	$5.22~~12.73 per kW~~
Generation Capacity	$3.68~~2.07 per kW~~
Transmission	$3.58~~2.20 per kW~~

Energy Charge Components (per kWh) (Unbundled):

Local Delivery	$0.000520

~~Summer (May – October)~~	~~On Peak~~	~~Off Peak~~
~~Local Delivery~~	~~$0.000343~~	~~$0.000343~~
~~Generation~~	~~$0.000100~~	~~$0.000100~~
~~Transmission~~	~~$0.000019~~	~~$0.000019~~

~~Power Supply Charge (per kWh):~~Power Supply Charges:

Component	
Base Power Supply Summer (May – October) On-Peak (per kWh)	$0.122510
Base Power Supply Summer (May – October) Off-Peak (per kWh)	$0.032110
Base Power Supply Winter (November – April) On-Peak (per kWh)	$0.092110
Base Power Supply Winter (November – April) Off-Peak (per kWh)	$0.030910
PPFAC (%) (see Rider -1 for current rate)	Varies

~~Summer (May – October)~~	~~On Peak~~	~~Off Peak~~

~~Base Power Component (per kWh)~~	~~$0.123580~~	~~$0.024716~~
~~PPFAC (%)~~	~~In accordance with Rider 1 - PPFAC~~	

~~Energy Charge Components (per kWh) (Unbundled):~~

~~Winter (November – April)~~	~~On-Peak~~	~~Off-Peak~~
~~Local Delivery Energy~~	~~$0.000343~~	~~$0.000343~~
~~Generation~~	~~$0.000100~~	~~$0.000100~~
~~Transmission~~	~~$0.000019~~	~~$0.000019~~

~~Power Supply Charge (per kWh):~~

~~Winter (November – April)~~	~~On-Peak~~	~~Off-Peak~~
~~Base Power Component (per kWh)~~	~~$0.093880~~	~~$0.022105~~
~~PPFAC (%)~~	~~In accordance with Rider 1 - PPFAC~~	

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 501
Superseding:

Lighting Service (LTG)

AVAILABILITY
At any point where the Company in its judgment has facilities of adequate capacity and suitable voltage available.

APPLICABILITY
Applicable to any Customer for private and public street lighting or outdoor area lighting where this service can be supplied from existing facilities of the Company. The Company will install, own, operate, and maintain the complete lighting installation including lamp and globe replacements. Not applicable to resale service.

To any Customer, including public agencies, for the lighting of streets, alleys, thoroughfares, public parks, playgrounds, or other public or private property where such lighting is controlled by a photocell and a contract for service is entered into with the Company.

CHARACTER OF SERVICE
Service is supplied on Company-owned fixtures and poles which are maintained by the Company. The poles, fixtures, and lamps available are the standard items stocked by the Company, and service is rendered at standard available voltages. Multiple or series street lighting systems may be installed at the option of the Company and at one standard nominal voltage.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

~~BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES:~~

The monthly bill shall be the sum of the following charges and adjustments for each light:

Service Charge (per month):	Overhead Service	Underground Service
Existing Wood Pole	$ 2.35~~2.18~~	$ 2.35~~2.18~~
New 30' Wood Pole (Class 6)	$ 4.68~~4.34~~	$ 7.04~~166.52~~
New 30' Metal or Fiberglass	$ 9.35~~8.66~~	$11.67~~11.8710.81~~

Lighting Charge:
Based on the rated wattage value of each lamp installed per month: $0.060516~~051681~~ per watt

Base Power Supply Charge: based on the rated wattage value of each lamp installed per month: $0.013110~~010113~~ per kWh

The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent~~-kWh~~ adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold. T~~. ~~he PPFAC rate changes annually every June 1.~~ Please see Rate Rider-1 for current rate.

Filed By:	Kentton C. Grant	Rate:	LTG
Title:	Vice President	Effective:	~~January 1, 2014~~Pending
District:	Entire Electric Service Area	Decision No.:	~~74235~~Pending

CONTRACT PERIOD
All lighting installations will require a contract for service as follows:

Three (3) years initial term for installations on existing facilities.

TERMS AND CONDITIONS

1. For each light, overhead extensions beyond one hundred fifty (150) feet and underground extensions beyond one hundred (100) feet will require specific agreements providing adequate revenue or arrangements for construction financing.
2. The Customer is not authorized to make connections to the lighting circuit or make attachments or alterations to the Company-owned pole.
3. Should a Customer request a relocation of a dusk-to-dawn lighting installation, the costs of such relocation must be borne by the Customer.
4. The Customer is expected to notify the Company when lamp outages occur.
5. The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.
6. The Company will require a non-refundable contribution for the installation of new construction for facilities of $150.00.
7. A late payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.
8. When a residential Customer's privately owned underground service cable has failed, the Customer has two (2) options. The Customer can have their cable repaired by a private electrical contractor which must comply with local governmental codes and ordinances or the Customer can bring their service entrance up to current Company standards. The Customer will be required to provide a service trench, conduit, conduit installation, backfill, landscape restoration and paving. The Company will furnish, install, own and maintain the underground single-phase cables to Customer's Company-approved Point of Delivery.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

UniSource Energy SERVICES

UNS Electric, Inc.

Original Sheet No.: 501-2
Superseding:

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

Filed By:	Kentton C. Grant	Rate:	LTG
Title:	Vice President	Effective:	~~January 1, 2014~~Pending
District:	Entire Electric Service Area	Decision No.:	~~74235~~Pending

UniSource Energy SERVICES

UNS Electric, Inc.

Original Sheet No.: 501-3
Superseding:

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

New 30' Wood Pole (Class 6) - Overhead	
Billing and Collections	$2.57~~1.57~~ per unit
Customer Delivery	$2.11~~2.77~~ per unit
New 30' Metal or Fiberglass - Overhead	
Billing and Collections	$5.14~~1.57~~ per unit
Customer Delivery	$4.21~~7.09~~ per unit
Existing Wood Pole – Underground	
Billing and Collections	$1.29~~1.57~~ per unit
Customer Delivery	$1.06~~0.61~~ per unit
New 30' Wood Pole Class 6 – Underground	
Billing and Collections	$3.87~~1.57~~ per unit
Customer Delivery	$3.17~~4.95~~ per unit
New 30' Metal or Fiberglass – Underground	
Billing and Collections	$6.42~~1.57~~ per unit
Customer Delivery	$5.25~~9.24~~ per unit
Lighting Charge	
Local Delivery	$0.054106~~045641~~ per watt
Generation~~gation~~ Capacity	$0.003250~~003140~~ per watt
Transmission	$0.003160~~002900~~ per watt

Filed By:	Kentton C. Grant	Rate:	LTG
Title:	Vice President	Effective:	~~January 1, 2014~~Pending
District:	Entire Electric Service Area	Decision No.:	~~74235~~Pending

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 601
Superseding:

Interruptible Power Service (IPS-F)

AVAILABILITY

~~Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.~~

~~Any new Customers taking service under this Rate must furnish, install, own, and maintain at each point of delivery all necessary Company approved equipment which will enable the Company to interrupt service with its master control station.~~
New Customers, including current Customers who relocate, are not eligible for service under this rate.

TRANSITION PERIOD

Customers taking service under this rate prior to January 1, 2014 will be given twenty-four (24) months from January 1, 2014 to furnish, install, own, and maintain at each point of delivery all necessary Company approved equipment which will enable the Company to interrupt service with its master control station. After December 31, 2015, if the Customer has not installed this equipment, they will be placed on the otherwise applicable firm rate.

APPLICABILITY

This service is normally provided at one point of delivery measured through one meter. More than one service and meter may be provided in instances where such is permitted under 230.2 (A) through (D) of the National Electric Code with prior approval of the UNS Electric Engineering Department.

To any Customer with a minimum demand of 50 kW and is interruptible within fifteen (15) minutes of notice by the Company. The Customer must be able to interrupt service for up to eight (8) hours per day.

Not applicable to resale, breakdown, temporary, standby or auxiliary service.

CHARACTER OF SERVICE

Service shall be three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises.

RATE

A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF ~~CUSTOMER~~BASIC SERVICE, DEMAND AND ENERGY CHARGES:

~~Customer~~Basic Service Charge: $75~~18~~.00 per month

Demand Charge: $6.52~~5.00~~ per kW

Energy Charge (per kWh):

	Delivery Services-Energy[~~1~~]	Power Supply Charges[~~1~~2] Base Power	PPFAC[~~1~~2]	Total[2~~3~~]
All kWh	$0.019790~~019408~~	$0.049821~~43760~~	Varies	$0.069611~~3168~~

Filed By:	Kentton C. Grant	Rate:	IPS-F
Title:	Vice President	Effective:	~~January 1, 2014~~Pending
District:	Entire Electric Service Area	Decision No.:	~~74235~~Pending

~~1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.~~

1~~2~~. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent~~-kWh~~ adjustment in accordance with ~~Rate~~ Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold~~. Please see Rider-1 for current rate.

2~~3~~. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

PENALTY FOR FAILURE TO INTERRUPT:

In the event that the Customer fails to interrupt its load when requested to do so by the Company, the Customer shall pay an additional charge as follows:

Billing Demand Charge per kW @ $25.00
Unbundled $/kWh Charge is entirely a Delivery Charge

For a second failure to interrupt in any twelve (12) month period, the Customer will revert to the otherwise applicable firm Rate for a period of at least twelve (12) months.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month. If demand is not metered, the billing demand shall be based on nameplate ratings of connected motors and equipment, or by a test as approved by the Company.

TERMS AND CONDITIONS

A late payment charge as stated in the Company's Rules and Regulations will be applied to account balances carried forward from prior billings.

The Company reserves the right to interrupt service to the Customer at any time.

Customers who qualify for service under this Rate must remain on the Rate for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach. Service hereunder shall require the Customer to enter into a Service Agreement with the Company for a term of one (1) year or longer, with a minimum Contract Demand at the Company's option in view of the anticipated demand of the Customer.

The Company will endeavor to provide the Customer with as much advance notice as possible of the required interruptions. However, the Customer shall interrupt service within fifteen (15) ~~ten (10)~~ minutes.

The Company reserves the right to have automatic equipment installed for immediate interruption of the Customer's load. Should the Company's automatic equipment fail to interrupt the load, no penalty will be assessed.

The Company shall not be responsible for any loss or damage caused by or resulting from interruption of service under this Rate.

Standby, supplemental or breakdown service shall not be rendered under this Rate.

Service under this Rate is for the exclusive use of the Customer and shall not be resold or shared with others, unless authorized by the Company.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Commission shall apply where not inconsistent with this rate.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

~~Customer~~Basic Service Charge Components (Unbundled):

Description	~~Customer~~Basic Service Charge
Meter Services	$ 1.25~~2.62~~ per month
Meter Reading	$ 7.83~~6.69~~ per month
Billing & Collection	$ 5.54~~7.05~~ per month
Customer Delivery	$ 60.38~~1.64~~ per month
Total	$ 75.00~~18.00~~ per month

Demand Charge (per kW) (Unbundled):

	Rate
Local Delivery	$1.85~~2.95~~
Generation Capacity	$2.37~~0.53~~
Transmission	$2.30~~1.52~~

Energy Charge Components (per kWh) (Unbundled):

	Rate
Local Delivery	$0.019790~~015400~~
~~Generation~~	~~$0.003841~~
~~Transmission~~	~~$0.000167~~

Power Supply Charges~~ (per kWh)~~:

Component	Rate
Base Power Supply (per kWh)	$0.049821~~043760~~
PPFAC (%) (see Rider-1 for current rate)	Varies

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 701
Superseding:

Rider R-1
Purchased Power and Fuel Adjustment~~or~~ Clause (PPFAC)

APPLICABILITY

The Purchased Power and Fuel Adjustment Clause (PPFAC) will be applied to all Ccustomers taking ~~Standard Offer~~ service from the Company pursuant to the Arizona Corporation Commission (ACC) Decision No. 70360 ~~dated~~ (May 27, 2008) and as updated and defined in the Company's PPFAC Plan of Administration approved in ACC Decision No. XXXXX~~74235~~.

RATE

The Customer's monthly bill shall consist of ~~the~~ applicable rate charges and adjustments in addition to the PPFAC. The percentage-based PPFAC adjustment~~or rate~~, as shown below ~~in the UNS Electric, Inc. Statement of Charges~~ which, reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. The percentage-based PPFAC adjustment will apply to the Customer's Base Power Charge. ~~is an amount expressed as a rate per kWh charge to reflect the cost to the Company for energy either generated or purchased.~~

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under this rider~~e above rate~~, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

This standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

UniSource Energy SERVICES

UNS Electric, Inc.

~~15th Revised~~Original Sheet No.: 701-1

Superseding ~~14th Revised Sheet No.~~ : ~~701-1~~

Purchased Power Fuel Adjustment Clause
RIDER R-1

APPLICABILITY: To all Company Rates, unless otherwise specified.

Redesign table due to the purposed changes for the percentage PPFAC

~~Month/Year~~	~~Effective Date~~	~~Customer Class~~	~~PPFAC Rate This Period~~	~~PPFAC Surcharge/ Credit This Period~~	~~PPFAC Average Base Rate~~	~~Total Average Retail Fuel and Purchased Power Rate This Period~~	~~Total Average Retail Fuel and Purchased Power Rate Last Period~~	~~Change~~	~~% Change~~
~~May 2014~~	~~5/1/2014~~	~~All Sales~~	~~($0.001871)~~	~~$0.0000~~	~~$0.057060~~	~~$0.055189~~	~~$0.055651~~	~~($0.000462)~~	~~-0.83%~~
~~June 2014~~	~~6/1/2014~~	~~All Sales~~	~~($0.002329)~~	~~$0.0000~~	~~$0.057060~~	~~$0.054731~~	~~$0.055189~~	~~($0.000458)~~	~~-0.83%~~
~~July 2014~~	~~7/1/2014~~	~~All Sales~~	~~($0.002783)~~	~~$0.0000~~	~~$0.057060~~	~~$0.054277~~	~~$0.054731~~	~~($0.000454)~~	~~-0.83%~~
~~August 2014~~	~~8/1/2014~~	~~All Sales~~	~~($0.003234)~~	~~$0.0000~~	~~$0.057060~~	~~$0.053826~~	~~$0.054277~~	~~($0.000451)~~	~~-0.83%~~
~~September 2014~~	~~9/1/2014~~	~~All Sales~~	~~($0.002787)~~	~~$0.0000~~	~~$0.057060~~	~~$0.054273~~	~~$0.053826~~	~~$0.000447~~	~~0.83%~~
~~October 2014~~	~~10/1/2014~~	~~All Sales~~	~~($0.003237)~~	~~$0.0000~~	~~$0.057060~~	~~$0.053823~~	~~$0.054273~~	~~($0.000450)~~	~~-0.83%~~
~~November 2014~~	~~11/1/2014~~	~~All Sales~~	~~($0.003220)~~	~~$0.0000~~	~~$0.057060~~	~~$0.053840~~	~~$0.053823~~	~~$0.000017~~	~~0.03%~~
~~December 2014~~	~~12/1/2014~~	~~All Sales~~	~~($0.003385)~~	~~$0.0000~~	~~$0.057060~~	~~$0.053675~~	~~$0.053840~~	~~($0.000165)~~	~~-0.31%~~
~~January 2015~~	~~1/1/2015~~	~~All Sales~~	~~($0.003488)~~	~~$0.0000~~	~~$0.057060~~	~~$0.053572~~	~~$0.053675~~	~~($0.000103)~~	~~-0.19%~~
~~February 2015~~	~~2/1/2015~~	~~All Sales~~	~~($0.003933)~~	~~$0.0000~~	~~$0.057060~~	~~$0.053127~~	~~$0.053572~~	~~($0.000445)~~	~~-0.83%~~
~~March 2015~~	~~3/1/2015~~	~~All Sales~~	~~($0.004162)~~	~~$0.0000~~	~~$0.057060~~	~~$0.052898~~	~~$0.053127~~	~~($0.000229)~~	~~-0.43%~~
~~April 2015~~	~~4/1/2015~~	~~All Sales~~	~~($0.003906)~~	~~$0.0000~~	~~$0.057060~~	~~$0.053154~~	~~$0.052898~~	~~$0.000256~~	~~0.48%~~

Issued: ~~April~~ ~~1~~ ~~2015~~
Month Day Year

Effective: ~~April~~ ~~1~~ ~~2015~~
Month Day Year

Rider R-2
Demand Side Management Surcharge (DSMS)

APPLICABILITY

The Demand Side Management Surcharge (DSMS) -will be applied to all Customers taking service from the Company ~~applies to all Customers, except customers who take service under the Customer Assistance Residential Energy Support (CARES) Rate or Low Income Medical Life Support Program (CARES-M) Rate in all territory served by UNS Electric, Inc.~~ as mandated by the Arizona Corporation Commission (ACC), unless otherwise specified. ~~CARES and CARES-M customers are exempt from any DSM surcharge.~~

RATES

The DSMS shall be applied to all monthly ~~net~~ bills ~~except for CARES customers~~. The DSMS will be assessed on a per kWh basis. The rates are shown in the UNS Electric Statement of Charges.

~~REQUIREMENTS~~

~~The 2014 UNS Electric DSMS is effective January 1, 2014 and will remain in effect until further ordered by the ACC.~~

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the ACC see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under this ridere ~~above rate~~, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company, and/or the price of, or revenue from, electric energy ~~gas sales~~ or service sold and/or the volume of energy~~gas sales~~ generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the ACC shall apply where not inconsistent with this rider~~rate~~.

Rider-3
Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS-F

AVAILABILITY

The Market Cost of Comparable Conventional Generation (MCCCG) calculation, Rider-3, is restricted solely to Rider-4, Net Metering for Certain Partial Requirements Service (NM-PRS-F). If for a billing month a Rider-4 NM-PRS-F Customer's generation facility's energy production exceeds the energy supplied by the Company, the Customer's bill for the next billing period shall be credited for the excess generation as described in Rider-4 NM-PRS-F. The excess kWh during the billing period shall be used to reduce the kWh supplied (not kW or kVA demand or customer/facilities charges) and billed by the Company during the following billing period. Each calendar year, for the customer bills produced in October (September usage) or a customer's "Final" bill - the Company shall credit the Customer for the positive balance of excess kWhs (if any) after netting against billing period usage. The payment for the purchase of the excess kWhs will be at the Company's applicable avoided cost, which for purposes of Rider-4 NM-PRS-F shall be the simple average of the hourly MCCCG as described below for the applicable year.

The Arizona Corporation Commission (ACC) provided guidance on defining MCCCG in the context of its REST Rules and identified the MCCCG as "the Affected Utility's energy and capacity cost of producing or procuring the incremental electricity that would be avoided by the resources used to meet the Annual Renewable Energy Requirement, taking into account hourly, seasonal and long term supply and demand circumstances. Avoided costs include any avoided transmission and distribution costs and any avoided environmental compliance costs." R14-2-1801.11.

CALCULATION/METHODOLOGY

For purposes of calculating credits to the Customer for Excess Generation, the unit price paid (Credit for Excess Generation) shall be the simple average of the MCCCG over the 8,760 hours (8,784 in a leap year) hours in the forecasted year. The MCCCG in each hour is based on whether native load requirements will be met by internally owned or contracted generation resources or if market purchases will be required to meet native load requirements. The following table provides a description of the MCCCG methodology. The hourly MCCCG cost determination criteria is based on the Market Condition and Dispatch Type. This method of cost determination is very data intensive and will be calculated annually by running UNS Electric's "Planning and Risk" modeling software, and the rate will be filed with the Commission by April 1 of each year.

RATE

The Customer monthly bill shall consist of the applicable r~~R~~ate charges and adjustments in addition to the Credit for Excess Generation based on the MCCCG. The MCCCG rate is an amount expressed as a rate per kWh charge that is approved by the ACC on or before June 1 of each year and effective with the first billing cycle in June, as shown in the UNS Electric Statement of Charges.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the ACC see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

MCCCG Cost Determination Matrix

Market Condition and Dispatch Type	Selling to Market from In House Real and Contracted Generation Sources	MCCCG Cost Based on Incremental Production/Purchase Cost of Base Load Generation for that hour			
	No Market Transactions from/to In House and Contracted Generation Sources				
	Purchasing from Day Ahead Market, but not Spot Market, to meet Native Load Requirements	MCCCG Cost Based on Average Day Ahead Market Price of Purchased Power for that hour			
	Purchasing from Spot Market to meet Native Load Requirements	MCCCG Cost Based on Average Spot Market Price of Purchased Power for that hour			

Incremental Production / Purchase of Base Load - The cost of the next kWh (incremental) amount of load that has to be provided by UNS Electric generation sources and/or purchased power. This will be dependent on the season, month and time of day.

If Day Ahead Market or Spot Market purchases are being used to provide for reliability support capacity to meet native load requirements by freeing up in house or contracted generation resources for regulation or spinning reserve purposes for support of native load requirements, that would still represent a Market Purchase for purposes of determining which matrix box is applicable.

Rider-4
Net Metering for Certain
Partial Requirements Service (NM-PRS-F)

AVAILABILITY

Available throughout the Company's entire electric service area to any Customer with a facility for the production of electricity on its premises using Renewable Resources[1], a Fuel Cell [2] or Combined Heat and Power (CHP)[3] to generate electricity, which is operated by or on behalf of the Customer, is intended to provide all or part of the Customer's electricity requirements, has a generating capacity less than or equal to 125% of the Customer's total connected load at the metered premise, or in the absence of load data, has capacity less than the Customer's electric service drop capacity, and is interconnected with and can operate in parallel and in phase with the Company's existing distribution system. Customer shall comply with all applicable federal, state, and local laws, regulations, ordinances and codes governing the production and/or sale of electricity.

For purposes of this r~~R~~ate, the following notes and/or definitions apply:

[1] Renewable Resources means natural resources that can be replenished by natural process. Renewable Resources include biogas, biomass, geothermal, hydroelectric, solar, or wind.

[2] Fuel Cell means a device that converts the chemical energy of a fuel directly into electricity without intermediate combustion or thermal cycles. The source of the chemical reaction must be derived from Renewable Resources.

[3] Combined Heat and Power (CHP) also known as cogeneration means a system that generates electricity and useful thermal energy in a single integrated system such that the useful power output of the facility plus one-half the useful thermal energy output during any 12-month period must be no less than 42.5 percent of the total energy input of fuel to the facility.

CHARACTER OF SERVICE

The service shall be single- or three-phase, 60 Hertz, at one standard nominal voltage as mutually agreed and subject to availability at the point of delivery. Primary metering will be used by mutual agreement between the Company and the Customer.

RATE

Basic Service~~Customer~~ Charges shall be billed pursuant to the Customer's standard offer rate otherwise applicable under full requirements of service.

Power sales and special services supplied by the Company to the Customer in order to meet the Customer's supplemental or interruptible electric requirements will be priced pursuant to the Customer's standard offer rate otherwise applicable under full requirements service.

Non-Time-of-Use Rates: For Customers taking service under a Standard Retail Rate that is not a Time-of-Use rate, the Customer Supplied kWh shall be credited against the Company Supplied kWh. The Customer's monthly bill shall be based on this net kWh amount. Any monthly Excess Generation will be treated in accordance with the provisions outlined below.

Time-of-Use Rates: For Customers taking service under a Standard Retail Rate that is a Time-of-Use rate, the Customer Supplied kWh during on-peak hours shall be credited against the Company Supplied kWh during on-peak hours. All Customer Supplied kWh during off-peak hours shall be credited against the Company Supplied kWh during off-peak hours. The Customer's monthly bill shall be based on this net kWh amount. Any monthly Excess Generation will be treated in accordance with the provisions outlined below.

EXCESS GENERATION
If for a billing month the Customer's generation facility's energy production exceeds the energy supplied by the Company, the Customer's bill for the next billing period shall be credited for the excess generation. That is, the excess kWh during the billing period shall be used to reduce the kWh supplied (not kW or kVA demand or customer/facilities charges) and billed by the Company during the following billing period. Customers taking service under a time-of-use rate who are to receive credit in a subsequent billing period for excess kWh generated shall receive such credit in the next billing period for the on-peak, or off-peak periods in which the kWh were generated by the Customer. Time-of-Use Customer's taking service in the billing month of April shall receive a credit to summer on-peak and summer off-peak usage in the billing month of May for any winter on-peak and/or winter off-peak excess generation for April.

Each calendar year, for the customer bills produced in October (September usage) or a customer's "Final" bill - the Company shall credit the Customer for the balance of excess kWhs after netting. The payment for the purchase of the excess kWhs will be at the Company's applicable avoided cost, which for purposes of this rate shall be the simple average of the hourly Market Cost of Comparable Conventional Generation (MCCCG) Rider-3 for the applicable year. The MCCCG, as it applies to this rate, is specified in Rider-3 MCCCG - Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS-F (Net Metering for Certain Partial Requirements Service).

METERING
The Company will install a bi-directional meter at the point of delivery to the customer and meter at the point of output from each of the Customer's generators. At the Company's request a dedicated phone line will be provided by the customer to the metering to allow remote interegation of the meters at each site. If by mutal agreement between company and customer that a phone line is impractical or can not be provided - the customer will work with company to allow for the installation of equipment, on or with customer facilities or equipment to allow remote acces to each meter. Any additional cost of communication, such as but not limited too, cell phone service fees will be the responsibility of the customer.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under this ridere ~~above rate~~, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider~~rate~~.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 705
Superseding:

Rider-5
Electric Service Solar Rider
(Bright Arizona Community Solar™)

APPLICABILITY

Rider-5 is for individually metered Customers who wish to participate in the Bright Arizona Community Solar Program. Under Rider-5, Customers will be able to purchase blocks of electricity from solar generation sources. Participation in Rider-5 is limited in the Company's sole discretion to the amount of solar generation available and subscription will be made on a first come, first served basis. In order to maximize subscription under Rider-5, the Company may limit the amount of solar block energy purchased by individual Customers. Rider-5 is further restricted to Customers being served under one of the following rates:

1. Residential Service Rate, RES-01 (RES-01 TOU is not applicable)
2. Small General Service Rate, SGS-10 (SGS-10 TOU is not applicable)
3. Medium~~Large~~ General Service Rate, M~~L~~GS (M~~L~~GS-TOU is not applicable)

Customers being served under self-generation riders or plans may not purchase power under Rider-5 (including, but not limited to Rider-4 Net Metering for Certain Partial Requirements Service (NM-PRS-F) ~~Rider-4~~ and Rider-10 Net Metering for Certain Partial Requirements Service (NM-PRS), Post June 1, 2015~~Non-Firm Power Purchase from Renewable Energy Resources and Qualifying Cogeneration Facilities of 100 kilowatts (kW) or Less Capacity Rider-101~~).

RATE

Customers can contract for a portion or up to their average annual usage in solar blocks of 150 kilowatt hours (kWh) each. Transmission and distribution charges will be applied to all energy delivered, including energy delivered under Rider-5. The Customer is responsible for paying (each month) all charges incurred under their applicable rate ~~schedule~~, and the total solar energy contracted for multiplied by the applicable solar block energy rate. Any demand based charges under the Customer's current rate will not be affected by elections under Rider-5. No discounts specified in any of the above-listed standard offer tariffs will apply to this ~~Rate~~rider. The rates are shown in the UNS Electric Statement of Charges.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider~~rate~~.

TAX CLAUSE

To the charges computed under this~~e above~~ rider~~Rate~~, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

TERMS AND CONDITIONS

1. Customers may contract for a portion or up to their average annual usage in solar blocks of 150 kWh. If Customer's annual average usage is not available, UNS Electric will apply the appropriate class average. This limit can be reviewed annually at the request of the Customer.

2. Each solar block's energy rate will be maintained for twenty years from the date of purchase. For the purposes of the twenty year energy rate, solar blocks will be attributed to the Customer's original service address. Transfer of service under Rider-5 is prohibited. Should the Customer cancel service for any reason, his or her subscription under Rider-5 will expire.

3. Customers may add or delete solar blocks once within a twelve month period. Any addition of solar blocks will be at the then offered solar block energy rate.

4. Solar blocks will be applied to the actual energy usage each month. Electricity used in excess of the purchased solar blocks will be billed at the Customer's regular energy rate. If electricity usage is below the amount covered by the solar block(s), then the excess kWhs will be rolled forward and credited again the Customer's usage in the following month. The Customer will still be responsible for the full cost of the block(s) each month.

5. Customers will be credited for the balance of any excess kWhs annually, or on their final bill should the Customer terminate service under Rider-5. Each year, for the bills produced in October (September usage), UNS Electric will credit Customers their excess kWhs after netting and reset their balance to zero. Credit for excess kWhs will be at the energy rate of the oldest solar block.

6. All contracted solar block kWhs and associated charges in a billing month will be excluded from the calculation of PPFAC and REST charges and/or credits.

UniSourceEnergy SERVICES

UNS Electric, Inc.

~~1st Alternate~~ Original Sheet No.: ~~REST-TS1~~706

Superseding: ~~Original Sheet No. REST-TS1~~

Rider-6
Renewable Energy Standard and Tariff (REST) Surcharge
REST-TS1 Renewable Energy Program Expense Recovery

APPLICABILITY
Mandatory, non-bypassable surcharge applied to all energy consumed by all Customers throughout Company's entire electric service area.

RATES
For all energy billed which is supplied by the Company to the Customer. The REST surcharge shall be applied to all monthly bills. The REST rates are shown in the UNS Electric Statement of Charges.

Note: An industrial Customer is one with monthly demand equal to or greater than 3,000 kW.

For non-metered services, the lesser of the load profile or otherwise estimated kWh required to provide the service in question, or the service's contract kWh shall be used in the calculation of the surcharge.

This charge will be a line item on Customer bills reading "Renewable Energy Standard Tariff."

Per Decision No. 73638, effective March 21, 2013, any Customer who has received incentives under the REST Rules, shall pay the average of the REST surcharge paid by members of their Customer class. This requirement shall apply to renewable systems reserved on and after January 1, 2012. Any Customer who has a renewable installation without incentives that is interconnected with UNS Electric's system shall pay the average of the REST surcharge paid by members of their Customer class. This requirement shall apply to renewable systems reserved on and after February 1, 2013. The average price is shown in the UNS Electric Statement of Charges.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this ~~pricing plan~~rider.

TAX CLAUSE
To the charges computed under this rider~~e above rate~~, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

Rider-7
Customer Self-Directed Renewable Energy Option
REST-TS2 Renewable Energy Standard Tariff

AVAILABILITY
Open to all Eligible Customers as defined at A.A.C. R14-02-1801.H.

APPLICABILITY
Any Eligible Customer that applies to the Company under this program and receives approval shall participate at its option.

PARTICIPATION PROCESS
An Eligible Customer seeking to participate shall submit to the Company a written application that describes the Distributed Renewable Energy (DRE) resources or facilities that it proposes to install and the estimated costs of the project. The Company shall have sixty (60) calendar days to evaluate and respond in writing to the Eligible Customer, either accepting or declining the project. If accepted, the Customer shall be reimbursed up to the actual dollar amounts of customer surcharge paid under the REST-TS1Tariff in any calendar year in which DRE facilities are installed as part of the accepted project. To qualify for such funds, the Customer shall provide at least half of the funding necessary to complete the project described in the accepted application, and shall provide the Company with sufficient and reasonable written documentation of the project's costs. Customer shall submit their application prior to May 1 of a given year to apply for funding in the following calendar year.

FACILITIES INSTALLED
The maintenance and repair of the facilities installed by a Customer under this program shall be the responsibility of the Customer following completion of the project. In order to be accepted by the Company for reimbursement purposes, the project shall, at a minimum, conform to the Company's System Qualification standards on file with the Commission. (REST Impolementation Plan, Renewable Energy Credit Purchase Program – RECPP, Distributed Generation Interconnection Requirements, Net Metering Tariff, Company's Interconnection Manual)

PAYMENTS AND CREDITS
All funds reimbursed by the Company to the Customer for installation of approved DRE facilities shall be paid on an annual basis no later than March 30th of each calendar year. All Renewable Energy Credits derived from a project, including generation and Extra Credit Multipliers, shall become the property of the Company and shall be applied towards the Company's Annual Renewable Energy Requirement as defined in A.A.C. R14-2-1801.B.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rider~~Rate~~.

RELATED ~~SCHEDULES~~RIDER

- REST-TS1 - Renewable Energy Program Expense Recovery

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 708
Superseding:

Rider R-8
Lost Fixed Cost Recovery (LFCR)

APPLICABILITY

The Lost Fixed Cost Recovery (LFCR) will be applied to all Customers taking service from the Company other than lighting as defined in the Company's LFCR Plan of Administration (POA). ~~As provided for in the POA, in the event a residential Customer chooses to contribute to this program by paying a fixed charge option, the monthly Customer Charge specified on the appropriate Standard Offer tariff will be charged in lieu of the percentage-based rate shown in the UNS Electric Statement of Charges.~~

CHANGE IN RATE

The LFCR recovers a portion of the authorized margin approved in the Company's most recent rate case that has been lost as the result of implementing Arizona Corporation Commission (ACC)-mandated Energy Efficiency and Distributed Generation programs. Each year, a percentage-based rate will be placed in effect and charged to the participating rate classes for the 12-month period the LFCR adjustment is applicable. The total year-on-year adjustment cannot exceed 2~~1~~% of the Company's most recent total combined retail calendar year revenues for all participating rate classes. The LFCR rate is shown in the UNS Electric Statement of Charges.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the ACC see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under th~~e~~is rider ~~above rate~~, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider~~Rate~~.

Filed By:	Kentton C. Grant	Rate:	R-8
Title:	Vice President	Effective:	~~January 1, 2011~~Pending
District:	Entire Electric Service Area	Decision No.:	~~74235~~Pending

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 709
Superseding:

Rider R-9
Transmission Cost Adjustor (TCA)

APPLICABILITY
The Transmission Cost Adjustor (TCA) will be applied to all Customers taking service from the Company as defined in the Company's TCA Plan of Administration (POA).

CHANGE IN RATE
The TCA recovers the change in transmission costs resulting from the Federal Energy Regulatory Commission (FERC) approved formula rate that is updated annually in accordance with the provisions of the Company's Open Access Transmission Tariff (OATT), available through the FERC eTariff website at: http://etariff.ferc.gov/TariffBrowser.aspx?tid=1697. The adjustment captures the difference between the level of transmission costs approved in the Company's last rate case and the amount calculated based on the FERC-approved formula rate. The adjustment can be a charge or a credit and will be updated annually as of the date set forth in the OATT.

> The TCA shall apply to all monthly bills either as a per kWh charge or as a per kW rate, depending on the Customer's effective service tariff, and is anticipated to become effective on the date the TCA is updated. The TCA rates are shown in the UNS Electric Statement of Charges.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under this ridere ~~above rate~~, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
This standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

Filed By:	Kentton C. Grant	Rate:	R-9
Title:	Vice President	Effective:	~~January 1, 2014~~Pending
District:	Entire Electric Service Area	Decision No.:	~~74235~~Pending

Rider-10
Net Metering for Certain Partial Requirements Service (NM-PRS), Post June 1, 2015

AVAILABILITY
Available throughout the Company's entire electric service area to any Customer with a facility for the production of electricity on its premises using Renewable Resources[1], a Fuel Cell [2] or Combined Heat and Power (CHP)[3] to generate electricity, which is operated by or on behalf of the Customer, is intended to provide all or part of the Customer's electricity requirements, has a generating capacity less than or equal to 125% of the Customer's total connected load at the metered premise, or in the absence of load data, has capacity less than the Customer's electric service drop capacity, and is interconnected with and can operate in parallel and in phase with the Company's existing distribution system. Customer shall comply with all applicable federal, state, and local laws, regulations, ordinances and codes governing the production and/or sale of electricity.

For purposes of this Rate, the following notes and/or definitions apply:

[1] Renewable Resources means natural resources that can be replenished by natural process. Renewable Resources include biogas, biomass, geothermal, hydroelectric, solar, or wind.

[2] Fuel Cell means a device that converts the chemical energy of a fuel directly into electricity without intermediate combustion or thermal cycles. The source of the chemical reaction must be derived from Renewable Resources.

[3] Combined Heat and Power (CHP) also known as cogeneration means a system that generates electricity and useful thermal energy in a single integrated system such that the useful power output of the facility plus one-half the useful thermal energy output during any 12-month period must be no less than 42.5 percent of the total energy input of fuel to the facility.

CHARACTER OF SERVICE
The service shall be single- or three-phase, 60 Hertz, at one standard nominal voltage as mutually agreed and subject to availability at the point of delivery. Primary metering will be used by mutual agreement between the Company and the Customer.

RATE
Residential or Small General Service Customers taking service under this rider must take service in accordance with the "Demand" option of the applicable standard offer rate.

Basic Service Charges shall be billed pursuant to the Customer's standard offer rate otherwise applicable under full requirements service.

All power sales defined as "kW", "kWh" and special services supplied by the Company to the Customer in order to meet the Customer's electric requirements will be priced pursuant to the Customer's standard offer rate otherwise applicable under full requirements service.

All energy produced by the Customer's generator in excess of the Customer's consumption at the time of the production is defined as excess generation and will be tracked throughout the month as excess generation and will be treated in accordance with the provisions outlined below.

EXCESS GENERATION
If at any time within a billing month the Customer's generation facility's energy production exceeds the energy consumed by the Customer, the Customer's bill for the same billing period shall be credited for the excess generation priced at the approved Renewable Credit Rate. In the event the credit exceeds the billable amount during that billing period, the unused credit will carry forward to the bill for the next billing period. The excess generation is treated the same for Standard Offer service Customers and Time-of-Use service Customers.

METERING
The Company will install a bi-directional meter at the point of delivery to the Customer and meter at the point of output from each of the Customer's generators. At the Company's request a dedicated phone line will be provided by the Customer to the metering to allow remote interrogation of the meters at each site. If by mutual agreement between Company and Customer that a phone line is impractical or cannot be provided - the Customer will work with Company to allow for the installation of equipment, on or with Customer facilities or equipment to allow remote access to each meter. Any additional cost of communication, such as but not limited to, cell phone service fees will be the responsibility of the Customer.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RENEWABLE CREDIT RATE
The "Renewable Credit Rate" is the rate equivalent to the most recent utility scale renewable energy purchased power agreement connected to the distribution system of the Company's affiliate, Tucson Electric Power Company, and is set forth in the UNS Electric Statement of Charges.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

Rider R–11
Renewable Credit Rate

AVAILABILITY
The Renewable Credit Rate, Rider R-11, is restricted solely to Rider-10, Net Metering for Certain Partial Requirements Service (NM-PRS), Post June 1, 2015. If for a billing month a Rider-10 NM-PRS Customer's generation facility's energy production exceeds the energy supplied by the Company at any time, the Customer's bill shall be credited for the excess generation as described in Rider-10 NM-PRS.

CALCULATION/METHODOLOGY
For production of electricity from a Customer generation facility using Renewable Resources as defined in Rider-10 NM-PRS, the Renewable Credit Rate is the rate equivalent to the most recent utility scale renewable energy Power Purchase Agreement (PPA) connected to the distribution system of the Company's affiliate, Tucson Electric Power Company.

For production of electricity from a Customer generation facility using a Fuel Cell or Combined Heat and Power (CHP) as defined in Rider-10 NM-PRS, the Renewable Credit Rate is the rate equivalent to the most recent utility scale energy PPA connected to the distribution system of the Company's affiliate, Tucson Electric Power Company, that uses a technology specific to the Customer's generation facility at the time service is requested.

If no utility scale PPA meeting the criteria above exists, the Renewable Credit Rate is equal to the UNS Electric Market Cost of Comparable Generation (MCCCG) as defined in Rider-3 MCCCG.

RATE
The Customer monthly bill shall consist of the applicable Rate charges and adjustments in addition to the Credit for Excess Generation based on the RCR as described in Rider-10 NM-PRS. The RCR rate is an amount expressed as a rate per kWh charge that is approved by the ACC on or before January 1 of each year and effective with the first billing cycle in January, as shown in the UNS Electric Statement of Charges.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the ACC see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

Rider R–12
Interruptible Service

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Available to Customers qualifying for and receiving electric service under rates applicable to service over 1,000 kW (either Time-of-Use or Non-Time-of-Use) and are willing to subscribe to at least 500 kW of interruptible load at a contiguous facility. This rider is not available for standby, temporary, resale or in conjunction with other interruptible rates.

CHARACTER OF SERVICE
Must meet all service requirements for the Customer's applicable Standard Offer tariff.

TERMS AND CONDITIONS OF SERVICE

1. Customers taking service under this rider are eligible for credits in exchange for curtailing load at the request of the Company.
2. Interruptions can be called for economic or non-economic reasons and are to be called at the sole discretion of the Company.
3. The Customer must designate each service point that may be available for interruption with a 10 minute notice. Interruption will be at the discretion of the Company.
4. No more than two interruption events will occur in a given calendar day.
5. A Customer will be limited to no more than two interruptions in a day during the five summer months for a maximum of six (6) hours for each daily interruption event, even if the duration per event is less than 6 hours.
6. To receive service under this Rider–12, the Customer will install, at the Customer's expense, all necessary communication, relay and breaker equipment to qualify for service under this rate, subject to Company approval and will pay for associated hardware cost. The Customer must maintain all Company-approved equipment at their service location necessary for the Company to provide interruption notification and to remotely interrupt the Customer from its master control station.
7. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.
8. Nothing herein prevents the Company from interrupting service for emergency circumstances, determined at the Company's sole discretion. Emergency interruptions, as defined by the Company's Rules and Regulations, shall not count as interruption events for purposes of this rider.
9. The standard Rules and Regulations of the Company, as on file with the Arizona Corporation Commission, shall apply where not inconsistent with this rider.
10. The total of all interruption events (excluding Emergency interruptions) will not exceed 120 hours per year.

BID COMMITMENT PERIOD
The Company will post Market Value Capacity Price (MVCP) (defined below) and available Interruptible Credits ($/kW) based on market value capacity for day-ahead dispatch notice for the coming months of May through September by March 15 in the same calendar year.

NOMINATION OF INTERRUPTIBLE LOAD BY CUSTOMER
Nomination will occur before April 15 of the calendar year of each interruption season. Participating Customers shall designate by service point the portion of their load that is Interruptible Load (in kW). A minimum of a thirty minute notice requirement, and a maximum interruption of six hours per event applies to all load nominated at a single service point. Customers with multiple service points may designate different maximum load (kW) for different contiguous service points. If the Customer intends to interrupt a specific activity or function at its operation, the Customer should state this activity or function at the time Interruptible Load is nominated. The minimum nomination of interruptible load summed over a participating Customer's contiguous service points shall be 1,000 kW.

INTERRUPTIBLE CREDIT
Customers who elect service under this Rider–12 will receive a monthly Interruptible credit for each of the five summer months in which an interruption may occur. The credit will be calculated by taking the Market Value Capacity Price applicable for the interruptible load season (May through September) times the nominated interruptible load of the individual Customer.

MARKET VALUE CAPACITY PRICE (MVCP)
The Market Value Capacity Price (MVCP) reflects opportunity cost of capacity as revealed through the Company's resource procurement process, adjusted to reflect line losses, and reserves avoided. Resource prices are sensitive and confidential information based on competitive bids; however this information will be made available to the Commission Staff and/or an Independent Monitor(s) for review. The MVCP is a price applicable to the five summer months only.

RECOVERY OF PROGRAM COSTS
The cost of the interruptible resource under this Rider–12 (the credits applied to qualifying Customers' bills) shall be treated as "Purchased Power" and shall be recorded in FERC account 555 and appropriately treated through the Purchased Power and Fuel Adjustment Clause (PPFAC) as any other prudent fuel or purchased power cost.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rider.

Rider-13
Economic Development Rider (EDR)

AVAILABILITY
Available throughout the Company's entire electric service area at all points where facilities of adequate capacity and required phase and suitable voltage are adjacent to the sites served. This rider is available for commercial or industrial standard offer Customers with a projected peak demand of 1,000 kW or more and a load factor of 75% or higher for the highest 4 coincident-peak months in a rolling 12-month period.

APPLICABILITY
This rider is applicable to the qualifying additional load of an existing or new Customer meeting the criteria specified herein. All provisions of the Customer's applicable standard offer rate will apply to the qualifying additional load, except as modified herein. This rider shall be available for five years from the effective date of the Economic Development Rider. Total program participation shall be limited to 50 MW of applicable Customer load.

New and existing Customers taking service under this rider must provide written documentation that they have qualified for at least one of the following Arizona state tax credits designed to promote business recruitment and expansion:

- Arizona's Quality Jobs Tax Credit (A.R.S. § 41-1525). The program provides a tax credit for net increases in full-time employees residing in the state and hired in qualified employment positions.
    - If located in a city or town with a population of 50,000 persons or more and a county of 800,000 or more, companies must make at least a $5 million capital investment, create at least 25 net new full-time jobs that pay 100 percent of the median county wage, and cover at least 65 percent of employee health insurance costs.
    - In any other location, companies must invest at least $1 million of capital and create at least 5 qualified employment positions.
- Qualified Facility Tax Credit (A.R.S. § 41-1512). The program provides a refundable tax credit for qualifying capital investment in a manufacturing facility – including a manufacturing-related research and development or headquarters facility – that creates new jobs paying at least 125 percent of the median county wage and covering at least 80 percent of employees' health care premiums.

If either or both of the above Arizona Revised Statutes are superseded by subsequent legislation, the effective Statute shall apply. Exceptions to any of the above criteria will be reviewed and evaluated by the Company on a case-by-case basis.

For purposes of this rider, the following notes and/or definitions apply:

[1] Economic Development means new or expanding business operations that build new facilities.

[2] Economic Redevelopment means new or expanding business operations that occupy existing vacant facilities.

CHARACTER OF SERVICE
Must meet all service requirements for the Customer's applicable Standard Offer tariff.

RATE
All provisions, charges, and adjustments in the Customer's applicable Standard Offer retail rate schedule will continue to apply to the qualifying additional load except as follows:

Category	Program Term	Discount on Total Bill before Taxes	Qualifications
Economic Development	5 years	Year 1: 20% Year 2: 15% Year 3: 10% Year 4: 5% Year 5: 2.5%	Meet (i) criteria for Arizona's Quality Jobs Tax Credit or (ii) Qualified Facility Tax Credit and create new/expanding load of 1,000 kW.
Economic Redevelopment	5 years	Year 1: 30% Year 2: 25% Year 3: 20% Year 4: 10% Year 5: 5%	Meet (i) criteria for Arizona's Quality Jobs Tax Credit or (ii) Qualified Facility Tax Credit and create new/expanding load of 1,000 kW, plus the business moves into an existing site.

ECONOMIC DEVELOPMENT RIDER SERVICE AGREEMENT
The Customer must execute an Economic Development Rider Service Agreement with the Company. The Service Agreement establishes the terms and conditions of participation in the program consistent with A.R.S. § 41-1525 and A.R.S. § 41-1512, the Arizona Corporation Commission's regulations, and this rider.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

Experimental Rider-14
Alternative Generation Service (AGS)

AVAILABILITY
Available throughout the Company's entire electric service area at all points where facilities of adequate capacity and required phase and suitable voltage are adjacent to the sites served. This rider is available for standard offer Customers who have a peak load of 2,500 kW or more at a single service point and are served under rates LPS or LPS-TOU.

Customers must have interval metering, advanced metering infrastructure, or an alternative in place at all times under this rider. Customers shall comply with all applicable federal, state, and local laws, regulations, ordinances and codes governing the production and/or sale of electricity.

All provisions of the Customer's applicable standard offer rate will apply in addition to this Experimental Rider-14, except as modified herein. This rider shall be available for four years from the effective date of Experimental Rider-14, unless extended by the Arizona Corporation Commission. Total program participation shall be limited to 10 MW of Customer load.

For purposes of this rider, the following notes and/or definitions apply:

[1] Generation Service means wholesale power delivered to UNS Electric by a Generation Service Provider.

[2] Generation Service Provider means a third party entity that provides wholesale power to the Company on behalf of a Customer. This entity must be legally capable of selling and delivering wholesale power to the Company.

[3] Imbalance Energy means the difference between the hourly delivered energy from the Generation Service Provider and the actual hourly metered loads for each Customer for all Customers that have selected the Generation Service Provider under this rider. Imbalance energy will be calculated by the Company.

[4] Imbalance Service means the calculation and management of the hourly deviations in energy supply for imbalance energy.

[5] Standard Generation Service means power provided by the Company to a retail Customer in conjunction with transmission and delivery services, at terms and prices according to a retail rate other than Experimental Rider-14.

[6] Total Load Requirements means the Customer's hourly load including losses from the point of delivery to the Company's transmission system to the Company's sites for the duration of the contract.

CHARACTER OF SERVICE
The service shall be three-phase, 60 Hertz, and at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

CUSTOMER PARTICIPATION PROCESS
The Company shall establish an initial enrollment period during which Customers can apply for service under this rider. If the applications for service are greater than the program maximum amount, then Customers shall be selected for enrollment through a lottery process as detailed in the program guidelines, which may be revised from time-to-time during the term of this rider.

DESCRIPTION OF SERVICES AND OBLIGATIONS

The Customer shall apply for service under this rider.

The Company shall conduct the enrollment process in accordance with the provisions of this rider.

The Customer shall select a Generation Service Provider to provide Generation Service in accordance with the timeline specified in the program guidelines.

The Company shall enter into a contract with the Generation Service Provider to receive delivery and title to the power on the Customer's behalf.

The Generation Service Provider shall provide to the Company on behalf of the Customer firm power sufficient to meet the Customer's Total Load Requirements for each of the elected metered accounts, and will attest in its contract with the Company that this condition is met. For the purposes of this rider, "firm power" refers to generation resources identified in Western System Power Pool Schedule C or a reasonable equivalent as determined by the Company.

Any incremental costs or penalties incurred by the Company as the result of actions or inactions of the Generation Service Provider will be the responsibility of the Customer to pay or arrange for resolution of or service under this rider will be terminated immediately and the provisions of the section referring to the Default of the Generation Service Provider will be applied.

The Company shall provide transmission, delivery and network services to the Customer according to normal retail electric service.

The Company will settle with the Generation Service Provider for Imbalance Service and other relevant costs on a monthly basis according to the program guidelines.

The Generation Service Provider shall bill the Company the monthly billed amounts for each Customer for Generation Service and Imbalance Service according to the program guidelines.

The Company shall bill the Customer for the Generation Service Provider's charged amounts and remit the amounts to the Generation Service provider including any applicable taxes and assessments.

The Customer will be responsible for paying for the cost of the power provided by the Generation Service Provider, as specified in the contract and this rider and will be subject to disconnection in the manner consistent with the Rules and Regulations for the equivalent retail service in the event of non-payment or late payment.

RATE

All provisions, charges, and adjustments in the Customer's applicable retail rate schedule will continue to apply except as follows:

1. The Base Power Charge will not apply.
2. The unbundled Generation components of the Demand Charge and Energy Charge for Delivery Services will not apply.
3. The Purchased Power and Fuel Adjustment Clause (PPFAC) will not apply, except that the Historical Component will apply for the first twelve months of service under this rider.

Experimental Rider-14 charges determined and billed by the Company include:

1. A monthly Management Fee of $0.0040 per kWh applied to the Customer's metered kWh.
2. A monthly Reserve Capacity charge equal to the applicable unbundled Generation components of the Demand Charge and the Energy Charge for Delivery Services will be applied to the Customer's billed kW and kWh, respectively. The Reserve Capacity charge will be applied to 100% of the Customer's monthly billed kW and kWh during the first twelve months of service under this rider and 25% of the Customer's billed kW and kWh thereafter until the expiration date of this Rider.
3. An initial charge or credit for fuel hedging costs, as describe herein.
4. Returning Customer charge, where applicable, as described herein.
5. Generation Service Provider Default charge, where applicable, as described herein.

Experimental Rider-14 Generation Service and Imbalance Service charges billed by the Company include:

1. Generation Service charges shall be charged at a rate specified in the contract between the Customer and the Generation Service Provider.
2. Imbalance Service charges shall be charged at a rate greater than $0.00 per kWh and less than or equal to the rate that the Company charges the Generation Service Provider for Imbalance Service as specified herein.

DELIVERY OF POWER TO THE COMPANY'S SYSTEM
Power provided by the Generation Service Provider must be firm power as defined above and delivered to the Company at a point of delivery as agreed to by the Company. The Generation Service Provider is responsible for the cost of transmission service to deliver the power to the Company's delivery point.

SCHEDULING
The Company shall serve as the scheduling coordinator. The Generation Service Provider shall provide monthly schedules of hourly loads along with day-ahead hourly load deviations from the monthly schedule to the Company according to the program guidelines. Line losses, in the amount of 3.3%, from the point of delivery to the Customer's sites shall be either scheduled or financially settled.

IMBALANCE SERVICE
The Company will provide Imbalance Service according to the terms and provisions in the Company's Open Access Transmission Tariff, Schedule 4. Imbalance Energy will be based on the Generation Service Provider's portfolio of Customer loads.

PPFAC AND HEDGE COST TRUE-UP
The Customer will be subject to the Purchased Power and Fuel Adjustment Clause (PPFAC) – historical component for the first twelve months of service under this rider. The Customer will also pay for the hedge cost associated with the Customer's Standard Generation Service at the time the Customer takes service under this rider. For the purpose of this rider, the Company will determine the applicable pro rata hedge cost based on the market price for hedge costs at the time the Customer takes service under this rider.

CONTRACT TERM AND REQUIREMENTS
The term of the contract with the Generation Service Provider shall be for not less than one year and shall not exceed the termination date of this rider or 4 years, whichever is shorter.

The Generation Service Provider and Customer will enter into a contract or contracts with the Company, stating the pertinent details of the transaction with the Generation Service Provider, including but not limited to the scheduling of power, location of delivery, and other terms related to the Company's management of the generation resource.

DEFAULT OF THE THIRD PARTY GENERATION SERVICE PROVIDER
In the event that the Generation Service Provider is unable to meet its contractual obligations, the Customer must notify the Company and select another Generation Service Provider within 60 days. Prior to execution of any new power contract, the Company shall provide the required power to the Customer, which will be charged at the Dow Jones Electricity Palo Verde Daily Index price for the power delivery date plus $20 per MWh. In addition, all other provisions of this rider will continue to apply.

If the Customer is unable to select another Generation Service Provider within sixty days, the Customer will automatically return to Standard Generation Service, and be subject to the conditions below.

RETURN TO COMPANY'S STANDARD GENERATION SERVICE
Customer may return to the Company's Standard Generation Service under their applicable retail rate schedule without charge if: (1) they provide one year notice (or longer) to the Company; or (2) if this rider is discontinued at the end of the 4-year experimental period; or (3) the Commission terminates the program prior to the end of the initial 4-year experimental period. Absent one of these three conditions, the Company will provide the Customer with generation service at the Dow Jones Electricity Palo Verde Daily Index price for the power delivery date plus $20 per MWh until the Company is reasonably able to integrate the Customer back into their generation planning and provide power at the applicable retail rate schedule. This transition will be at the Company's determination but no longer than 1 year. The returning Customer must remain with the Company's Standard Generation Service for at least 1 year and compensate the Company for all fixed generation costs avoided by the Customer during the period the Customer was receiving service under this rider.

LOST FIXED COST RECOVERY
UNS Electric will track all non-recovered revenues related to generation fixed costs for future recovery in the Company's Lost Fixed Cost Recovery (LFCR).

CREDIT REQUIREMENTS
A Generation Service Provider or its parent company must have at least an investment grade credit rating or demonstrate creditworthiness in the form of either a 3rd-party guarantee from an investment grade rated company, surety bond, letter of credit, or cash in accordance with the Company's standard credit support rules.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

UniSource Energy SERVICES

UNS Electric, Inc.

Original Sheet No.: 801

Superseding:

UNS ELECTRIC STATEMENT OF CHARGES

Fee No.	Description	Rate	Effective Date	Decision No.
1.	Service Transfer Fee	$26.00	~~January 1, 2014~~Pending	~~74235~~Pending
2.	Customer-Requested Meter Re-read	$26.00	~~January 1, 2014~~Pending	~~74235~~Pending
3.	Special Meter Reading Fee (including Customer Self-Reads)	$26.00	~~January 1, 2014~~Pending	~~74235~~Pending
4.	Service Establishment, ~~and~~ Reestablishment or Reconnection of Service under usual operating procedures During Regular Business Hours	$47.00~~41.00~~	~~January 1, 2014~~ Pending	~~74235~~Pending
5.	Service Establishment, ~~and~~ Reestablishment or Reconnection of Service under usual operating procedures After Regular Business Hours (includes Saturdays, Sundays and Holidays) ~~– Single Phase Service~~	$149.00~~137.00~~	~~January 1, 2014~~Pending	~~74235~~Pending
6.	Service Reestablishment under other than usual operating procedures (including Automated Meter Opt-Out Set Up Fee)	$196.00~~150.00~~	~~January 1, 2014~~Pending	~~74235~~Pending
7.	Meter Test	$79.00~~74.00~~	~~January 1, 2014~~Pending	~~74235~~Pending
8.	Consumption History Request and Interval History Request	$65.00 per hour	Pending	Pending
9~~8~~.	Returned Payment Fee	$10.00	~~January 1, 2014~~Pending	~~74235~~Pending
10~~9~~.	Late Payment Finance Charge	1.5%	~~January 1, 2014~~Pending	~~74235~~Pending

UniSourceEnergy SERVICES

UNS Electric, Inc.

~~Fourth Revised~~ Substitute Original Sheet No.: 801-1

Superseding Original Sheet No. ~~Third Revised Sheet No:~~ 801-1

UNS ELECTRIC STATEMENT OF CHARGES

Description	Rate	Effective Date	Decision No.
Rider R-1 – Purchased Power and Fuel Adjustment Clause (PPFAC)	Varies–See Rider-1	January 1, 2014	74235
Rider R-2 – Demand Side Management Surcharge (DSMS)	$0.0015 per kWh	August 1, 2014	74599
Rider R-3 – Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS	$0.03697 per kWh	June 1, 2014	74387
Rider R-5 – Electric Service Solar Rider (Bright Arizona Community Solar™) Solar Block Energy Rate for Residential Electric Service, Rate R-01 Solar Block Energy Rate for General Service, Rate SGS-10 Solar Block Energy Rate for Large General Service, Rate LGS	 $0.087445 per kWh $0.085495 per kWh $0.077991 per kWh	January 1, 2011 through December 31, 2013	72034
Rider R-5 – Electric Service Solar Rider (Bright Arizona Community Solar™) Solar Block Energy Rate for Residential Electric Service, Rate R-01 Solar Block Energy Rate for General Service, Rate SGS-10 Solar Block Energy Rate for Large General Service, Rate LGS	 $0.084510 per kWh $0.078241 per kWh $0.076603 per kWh	January 1, 2014 Through pending	74235
Rider R-5 – Electric Service Solar Rider (Bright Arizona Community Solar™) Solar Block Energy Rate for Residential Electric Service, Rate R-01 Solar Block Energy Rate for General Service, Rate SGS-10 Solar Block Energy Rate for Medium General Service, Rate MGS	 $0.069260 per kWh $0.068610 per kWh $0.068440 per kWh	Pending	Pending
Rider R-6 – Renewable Energy Standard and Tariff Surcharge REST-TS1 Renewable Energy Program Expense Recovery Monthly Cap For Residential Customers: For Commercial Customers: For Industrial Customers: For Lighting (PSHL):	$0.01000 per kWh Monthly Cap $3.40 per month $90.00 per month $10,000 per month $90.00 per month	January 1, 2015	74877

Filed By: Kentton C. Grant
Title: Vice President
District: Entire Electric Service Area

Rate: Statement of Charges
Effective: ~~January 1, 2014~~Pending
Decision No.: ~~74235~~Pending

UniSourceEnergy SERVICES

UNS Electric, Inc.

~~Second Revised~~ Substitute Original Sheet No.: 801-2

Superseding ~~Second Substitute First Revised Sheet No.~~ Original Sheet No.: 801-2

UNS ELECTRIC STATEMENT OF CHARGES

Description	Rate	Effective Date	Decision No.
Rider R-6 – Renewable Energy Standard and Tariff Surcharge REST-TS1 Renewable Energy Program Expense Recovery Per Decision No. 73638, customers receiving incentives on or after January 1, 2012 shall pay the average of the REST surcharge paid by members of their customer class. Customer with renewable installations without incentives that is interconnected with UNSE's system on or after February 1, 2013 shall pay the average of the REST surcharge paid by members of their customer class. The average price by class shall be the following: Monthly Cap For Residential Customers: For Commercial Customers: For Industrial Customers: For Lighting (PSHL):	Monthly Cap $3.00 per month $19.50 per month $9,763 per month $1.30 per month	January 1, 2015	74877
Rider R-8 Lost Fixed Cost Recovery (LFCR) Mechanism ~~– Energy Efficiency~~ ~~Lost Fixed Cost Recovery (LFCR) Mechanism – Distributed Generation~~	~~0.3058%~~ pending ~~0.2716%~~	pending~~September 1, 2014~~	pending~~74694~~
Rider R-9 Transmission Cost Adjustor (TCA) – $/kWh charge (Non-Demand) Transmission Cost Adjustor (TCA) – $/kW charge (Demand)	$0.00114 per kWh $0.4329 per kW	June 9, 2014	74235
Rider R-11 Renewable Credit Rate	Pending	Pending	Pending

Bill Estimation Methodologies

UNS Electric, Inc. (UNS Electric) regularly encounters situations in which UNS Electric cannot obtain a complete and valid meter read. No matter the cause of the need to estimate the read, the following methods are used depending on the circumstances.

PREVIOUS YEAR FORMULA

SAME CUSTOMER WITH AT LEAST ONE YEAR OF HISTORY

UNS Electric would generate a bill based on Customer usage from the previous year using the "PREVIOUS YEAR" formula as follows:

LAST YEAR'S USAGE FOR SAME MONTH / NUMBER OF DAYS IN BILLING PERIOD = PER DAY USAGE
(FOR "TIME OF USE" (TOU) THIS WOULD BE APPLIED TO EACH PERIOD)

PER DAY USAGE X NUMBER OF DAYS IN THIS MONTH'S CYCLE = ESTIMATED USAGE
(FOR TOU THIS WOULD BE APPLIED TO EACH PERIOD)

PREVIOUS MONTH FORMULA

SAME CUSTOMER AT SAME PREMISE WITH LESS THAN ONE YEAR OF HISTORY

UNS Electric would generate a bill based on Customer usage from the previous month using the "PREVIOUS MONTH" formula as follows:

LAST MONTHS USAGE / NUMBER OF DAYS IN BILLING PERIOD = PER DAY USAGE
(FOR TOU THIS WOULD BE APPLIED TO EACH PERIOD)

PER DAY USAGE X NUMBER OF DAYS IN THIS MONTH'S CYCLE = ESTIMATED USAGE
(FOR TOU THIS WOULD BE APPLIED TO EACH PERIOD)

TREND FORMULA

NEW CUSTOMER AT SAME PREMISE

UNS Electric would generate a bill using the "TREND" formula, based on Customer's usage trend as described below:

UNS Electric's customer information system (CIS) would generate a bill based on trend. Customers are assigned to a Trend area which differentiate consumption based on different geographic areas. Secondly, the Customer is assigned to a Trend class which is used to differentiate consumption trends based on the type of service and type of property. An example of this would be residential, commercial, and industrial usage. Thirdly, all consumption is identified using unit of measure code and a time of use code. Within UNS Electric's CIS, a trend record is created from each billed service. This record becomes part of a trend table. During estimation, consumption from three prior bill cycles is compared to the consumption from the same cycle in the previous month to determine a trend. This trend, plus a tolerance, is used to create a usage amount for bill estimation.

CUSTOMER'S USAGE IN PREVIOUS PERIOD/ AVERAGE CUSTOMER'S USAGE IN PREVIOUS PERIOD X AVERAGE CUSTOMER'S USAGE IN CURRENT PERIOD = ESTIMATED CONSUMPTION FOR REGISTER READ

NO HISTORY

UNS Electric would not generate a bill until a good meter read was acquired then use known consumption to estimate previous bills.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 802-1
Superseding: ______________

Demand Estimate

For accounts that have a demand billing component UNS Electric collects interval data. This interval data is used to manually estimate demands using the following methodologies:

SAME CUSTOMER AT SAME PREMISE WITH AT LEAST ONE YEAR OF HISTORY

UNS Electric would generate a bill based on Customer usage from the previous year using the following formula:

LAST YEAR'S DEMAND FOR SAME MONTH = ESTIMATED DEMAND

NEW CUSTOMER AT SAME PREMISE WITH AT LEAST ONE YEAR OF HISTORY

UNS Electric would generate a bill based on Customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

SAME CUSTOMER AT SAME PREMISE WITH LESS THAN ONE YEAR OF HISTORY

UNS Electric would generate a bill based on Customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

NEW CUSTOMER AT SAME PREMISE WITH LESS THAN ONE YEAR OF HISTORY

UNS Electric would generate a bill based on Customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

NO HISTORY

UNS Electric would not generate a bill until a good demand read was acquired then use known demand to estimate previous bills.

GUIDELINES FOR ELECTRIC LOAD CURTAILMENT

INTRODUCTION
While UNS Electric, Inc. (UNS Electric) strives to provide an uninterrupted supply of electricity, conditions could exist on UNS Electric's electric power system where:

- The power supply would be insufficient to meet the electric load demands during peak period. This condition will be classified as a "Bulk Power Supply Emergency".

- The transmission delivery would be insufficient to meet electric load demands. This will be considered a "Transmission Emergency".

Should a "Bulk Power Supply Emergency" or a "Transmission Emergency" seem imminent the following steps will be implemented as appropriate.

1. Evaluate alternative power supplies or Company owned generation.

2. Call on Interruptible Customers to interrupt load.

3. Reschedule any scheduled maintenance of the transmission system.

4. Reduce all non-essential Company uses such as office lighting, electric cooling and heating, etc.

5. Contact Western Area Power Administration for possible assistance.

6. Contact Nevada Energy and Aha Macav Power Service for possible emergency assistance.

7. Reduce distribution feeder voltage up to 5%, where possible.

Should additional remedial action be warranted, UNS Electric will make a public appeal via local radio stations and television for the voluntary curtailment of electric consumption by its customers.

Should voluntary curtailment result in insufficient load reduction to mitigate the emergency, the Arizona Corporation Commission (ACC) has directed UNS Electric to institute mandatory involuntary curtailment, pursuant to ACC Decision No. 42097 and Arizona Administrative Code R14-2-208, Provision of Service, Paragraph E.

CUSTOMER LOAD DEFINITIONS

Essential Loads: Loads that are necessary to the health, safety and welfare of the public or some portion or member thereof, such as police, fire service, national defense, sewage facilities, domestic water facilities, hospitals, essential medical devices (such as iron lungs, oxygen pumps or similar uses) and where uninterrupted electric service is essential to the providing of such essential uses or services. These loads will not be interrupted unless an area needs to be dropped to maintain the stability of the electric system, or adequate on-site generation is available to cover the Essential load.

Critical Loads: That portion of the electric load of those non-residential customers which in the event of interruption of service would cause excessive damage to the equipment or material in process or perishable items or where such interruption would create grave hazards to the employee's or the public. These areas will not be interrupted unless an area needs to be dropped to maintain the stability of the electric system, or adequate on–site generation is available to cover the Critical load level.

Others: All customers not meeting the above definitions will be interrupted, with or without, notice if voluntary curtailment measures are not sufficient to alleviate the problem.

LOAD CURTAILMENT NOTIFICATION

UNS Electric's load is served primarily by Tucson Electric Power Company (TEP) under a Power Services Agreement. Energy from TEP resources is delivered to UNS Electric's load areas in Mohave and Santa Cruz Counties through the bulk power transmission system of the Western Area Power Administration (WAPA). UNS Electric's load is in the control area of TEP for Power Supply purposes and in WAPA's control area for Transmission purposes. Either control area could initiate a call for load curtailment due to a system or regional power supply or transmission emergency. Local Transmission Emergencies could occur, affecting portions of UNS Electric's service area only.

Should either voluntary or involuntary load curtailment become necessary:

1. UNS Electric's Mohave Dispatch Center will be notified of a regional curtailment emergency by either TEP's Energy Control Center or the WAPA's Transmission Dispatch Desk.

2. UNS Electric's Mohave Dispatch Center will notify Mohave Management of the nature and type of curtailment emergency.

3. Mohave Management will notify Company Management, District Operations Management and the ACC of the nature of the curtailment.

4. District Customer Service Personnel will, if time permits:

   - Notify Interruptible Customer to drop load;
   - Notify key customers of the nature of the curtailment and request voluntary load; reductions or activation of on-site generation (if any);
   - Call local radio stations to request public announcements;
   - Notify County Emergency Management, and;
   - Notify City and County Police and Fire Departments.

5. District Operations Personnel will notify supervisory and assigned staff to report to their respective duty stations.

VOLUNTARY LOAD CURTAILMENT

If conditions allow for advanced notification, UNS Electric shall evaluate activating its own generation and will ask the public for a voluntary curtailment. In addition, all Interruptible Customers and Large Load Customers will be called by pre-assigned individuals to request load interruption as provided for under the Tariff or voluntary load reduction where no tariff exists.

INVOLUNTARY LOAD CURTAILMENT

Should the voluntary curtailment result in an insufficient reduction in load, Division Operations Management will determine the amount of additional load to curtail. Blackout periods are to be approximately 30 to 60 minutes in duration.

After proper notification Division Operations Management will utilize the capabilities of the System Control and Data Acquisition System ("SCADA") and manual operation to shed load throughout the District operations areas (Kingman, Lake Havasu City and Santa Cruz) based on circuit classification, unless the emergency is of a local nature. Individual Distribution Circuits will be classified for curtailment, according to the type of customers served on that feeder, as defined in the Guide to Circuit Loading for each District.

DISTRIBUTION CIRCUIT CLASSIFICATIONS

Essential: Circuits that serve essential customers will be so identified and will not be interrupted, unless an area must be dropped to maintain electric system stability.

Critical: Circuits that serve critical customers will be so identified and will not be interrupted, unless an area must be dropped to maintain electric system stability. Critical Customers will be notified and required to curtail the non-critical portions of their load. If a customer with a critical load refuses or fails to curtail their electric consumption down to the critical load, the customer shall not be considered to have a critical load and can be curtailed 100%.

Large Load Customers:

1. Circuits that serve Large Load Customers will be so identified and will not be interrupted until proper notice is given, unless an area must be dropped to maintain electric system stability.

2. Customers, who can take 100 percent curtailment if given sufficient notice, will be rotated on the same schedule as the "Others" circuits until the emergency is terminated by UNS Electric.

3. Customers served by circuits that cannot be rotated* will be notified. They will be required to reduce their load to their pre-determined level, in a rotating order and with a frequency or repetition necessary to meet the emergency situation.

Others:

Circuits that serve all remaining customers will be so identified and rotated without notice. Rotation of these circuits will be for a duration and frequency necessary to meet the emergency situation.

Customers on a non-rotating circuit* who normally could be rotated, will be required to curtail load. If these customers do not curtail to the extent needed, UNS Electric may discontinue or disconnect service and refuse to re-establish service until after the emergency condition is terminated.

***Non-Rotating Circuits are so classified based on the specific nature of the electric distribution system or due to having critical or essential customers served by that feeder.**

EMERGENCY INVOLUNTARY CURTAILMENT
In the event a major electrical disturbance threatens the interconnected Southwest system with blackout conditions or/and unexpected shortages of power that do not allow for the implementation of the Electric Curtailment Plan, emergency devices such as under-frequency/under-voltage load shedding relays will automatically shed load to maintain system stability, and the Company will resort to emergency operating procedures. These circuits will remain out of service until the Company can move from the emergency procedure to the Electric Load Curtailment Plan or the emergency is resolved.

INVOLUNTARY CURTAILMENT BY TRANSMISSION PROVIDER
UNS Electric purchases transmission service from the WAPA to deliver its power supply requirements. WAPA's Transmission Dispatch Desk would notify the UNS Electric Arizona Dispatch Center of situations on the bulk transmission system requiring load curtailment in the Company's service area.

ELECTRIC LOAD AND CURTAILMENT PLAN
A detailed electric load and curtailment plan will be kept on file with the ACC. This plan will contain specific procedures for implementation of the above, along with the name(s) and telephone number(s) of the appropriate Company personnel to contact in the event implementation of the plan becomes necessary. Updates to the plan will be filed annually or when they occur. Its amendments will become effective upon submission to the ACC.

The Company will contact the Director of the Utilities Division, or their designee, as soon as practical for any curtailment pursuant to this Tariff.

Rates for Power and Energy Transactions With Qualifying Facilities That Receive Full Requirements 100 kW or Less (QF-A)

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises. For all Qualifying Facilities (QF) that have entered into a Service Agreement with the Company.

APPLICABILITY
To all QFs with 100 kW or less operating in the Buy/Sell Mode for full requirements, supplemental power, stand-by power, and maintenance power service. To take service under QF-A, the customer must take service under a standard offer rate option with a demand charge.

CHARACTER OF SERVICE
Electric sales to the Company must be single or three phase, 60 Hertz, at a standard voltage subject to availability at the premises. The QF will have the option to sell energy to the Company at a voltage level different from that for purchases from the Company, however, the QF will be responsible for all costs incurred to accommodate such an arrangement.

DEFINITIONS

1. Qualifying Facilities - Cogeneration and small power production facilities where the facility's generator(s) and load are located at the same premise and that otherwise meet qualifying criteria for size, fuel use, efficiency and ownership as promulgated in 18 C.F.R., Chapter I, Part 292, Subpart B of Federal Energy Regulatory Commission regulations.

2. Buy/Sell Mode of Operation - The QF's total generation output is delivered to the Company and the QF's full requirements for service are provided by the Company or no electric requirements are required by the QF.

3. Full Requirements Service - Any instance whereby the Company provides all the electric requirements of a QF.

4. Energy - Electric energy which is supplied by the QF.

5. Firm Capacity - Capacity available, upon demand, at all times (except for forced outages and scheduled maintenance) during the period covered by the Agreement from the QF with an availability factor of at least 80%, as defined by the North American Electric Reliability Council.

6. Net Energy - The total kilowatt hours (kWh) sold to the QF by the company less the total kWhs purchased by the Company from the QF.

7. Supplemental Power - Electric capacity and energy supplied by the Company regularly used by the QF in addition to that which the facility generates itself.

8. Stand-by Power - Electric capacity and energy supplied by the Company to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

9. Maintenance Power - Electric capacity and energy supplied by the Company during scheduled outages of the QF.

10. Purchase Agreement - Agreements for the purchase of electric energy and capacity from and the sale of power to the QF entered into between the Company and QF.

Net Bill method:
The kWhs sold to the Company shall be subtracted from the kWhs purchased from the Company. If the calculation is positive, the Net Energy kWhs received from the Company will be priced at the applicable Electric Rate under which the QF would otherwise purchase its full requirements service. If the calculation is negative, the Net Energy kWhs delivered to the Company will be priced at the purchase rate shown below.

RATES FOR SALES TO QFs
The rates and billings for sales of energy and capacity to the QF shall be billed pursuant to the Customer's standard offer tariff otherwise applicable under full requirements service.

RATES FOR PURCHASES FROM QFs
Basic Service charges shall be billed pursuant to the Customer's standard offer tariff otherwise applicable under full requirements of service.

Rates for Energy purchased from the QF shall be priced at short-run avoided cost.

Rates for Firm Capacity purchased from the QF shall be priced at avoided cost based upon deferral of capacity additions indicated in Company's resource plan.

ADJUSTMENTS
Purchased Power Fuel Adjuster Clause (PPFAC) is a percent monthly adjustment in accordance with the PPFAC Rider No. 1. The PPFAC reflects increases or decreases in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. See Rider-1 for current rate.

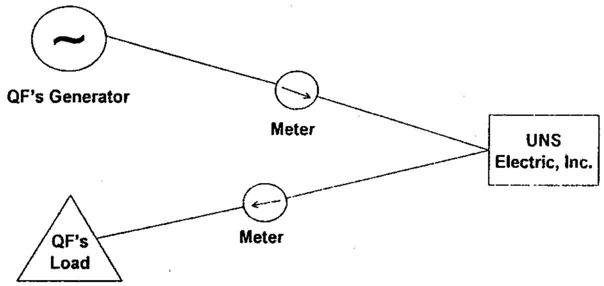
CONTRACT PERIOD
As provided for in the Service Agreement.

TERMS AND CONDITIONS
Subject to:

The Service Agreement, and

A delayed payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

METER CONFIGURATION



UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rate.

Rates for Power and Energy Transactions With Qualifying Facilities That Receive Partial Requirements 100 kW or Less (QF-B)

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises. For all Qualifying Facilities (QF) that have entered into a Service Agreement with the Company.

APPLICABILITY

To all QFs with 100 kW or less operating in the Partial Requirements Mode for partial requirements, supplemental power, stand-by power, and maintenance power service. To take service under QF-B, the customer must take service under a standard offer rate option with a demand charge.

CHARACTER OF SERVICE

Electric sales to the Company must be single or three phase, 60 Hertz, at a standard voltage subject to availability at the premises. The QF will have the option to sell energy to the Company at a voltage level different from that for purchases from the Company, however, the QF will be responsible for all costs incurred to accommodate such an arrangement.

DEFINITIONS

1. Qualifying Facilities - Cogeneration and small power production facilities where the facility's generator(s) and load are located at the same premise and that otherwise meet qualifying criteria for size, fuel use, efficiency and ownership as promulgated in 18 C.F.R., Chapter I, Part 292, Subpart B of Federal Energy Regulatory Commission regulations.

2. Partial Requirements Mode of Operation - A QF's generation output first goes to supply its own electric requirements with any excess energy (over and above its own requirements) then being sold to the Company. The Company supplies the QF's electric requirements not met by the QF's own-generation facilities. This also may be referred to as the "parallel mode" of operation.

3. Energy - Electric energy which is supplied by the QF

4. Firm Capacity - Capacity available, upon demand, at all times (except for forced outages and scheduled maintenance) during the period covered by the Agreement from the QF with an availability factor of at least 80%, as defined by the North American Electric Reliability Council.

5. Net Energy - The total kilowatt hours (kWh) sold to the QF by the company less the total kWhs purchased by the Company from the QF.

6. Supplemental Power - Electric capacity and energy supplied by the Company regularly used by the QF in addition to that which the facility generates itself.

7. Stand-by Power - Electric capacity and energy supplied by the Company to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

8. Maintenance Power - Electric capacity and energy supplied by the Company during scheduled outages of the QF.

9. Purchase Agreement - Agreements for the purchase of electric energy and capacity from and the sale of power to the QF entered into between the Company and QF.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 805-1
Superseding:

RATES FOR SALES TO QFs
The rates and billings for sales of energy and capacity to the QF shall be billed pursuant to the Customer's standard offer tariff otherwise applicable under full requirements service.

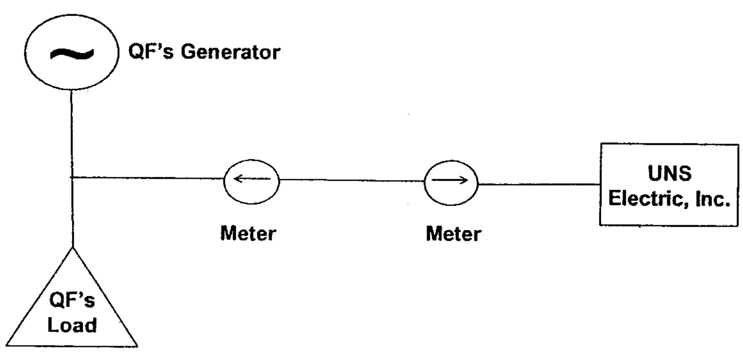
RATES FOR PURCHASES FROM QFs
Basic Service~~Customer~~ charges shall be billed pursuant to the Customer's standard offer tariff otherwise applicable under full requirements of service.

Rates for Energy purchased from the QF shall be priced at short-run avoided cost.

Rates for Firm Capacity purchased from the QF shall be priced at avoided cost based upon deferral of capacity additions indicated in Company's resource plan.

ADJUSTMENTS
Purchased Power Fuel Adjuster Clause (PPFAC) is a percent~~-kWh~~ monthly adjustment in accordance with the PPFAC Rider No. 1. The PPFAC reflects any increases or decreases in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. See Rider-1 for current rate.

METER CONFIGURATION



CONTRACT PERIOD
As provided for in the Service Agreement.

TERMS AND CONDITIONS
Subject to:

The Service Agreement, and

A delayed payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rate.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 806
Superseding:

Rates for Power and Energy Transactions With Qualifying Facilities That Receive Optional Service Over 100 kW (QF-C)

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises. For all Qualifying Facilities (QF) that have entered into a Service Agreement with the Company.

APPLICABILITY
To all QFs with over 100 kW operating in the Partial Requirements Mode for partial requirements, supplemental power, stand-by power, and maintenance power service.

CHARACTER OF SERVICE
Electric sales to the Company must be single or three phase, 60 Hertz, at a standard voltage subject to availability at the premises. The QF will have the option to sell energy to the Company at a voltage level different from that for purchases from the Company, however, the QF will be responsible for all costs incurred to accommodate such an arrangement.

DEFINITIONS

1. Qualifying Facilities - Cogeneration and small power production facilities where the facility's generator(s) and load are located at the same premise and that otherwise meet qualifying criteria for size, fuel use, efficiency and ownership as promulgated in 18 C.F.R., Chapter I, Part 292, Subpart B of Federal Energy Regulatory Commission regulations.

2. Partial Requirements Mode of Operation - A QF's generation output first goes to supply its own electric requirements with any excess energy (over and above its own requirements) then being sold to the Company. The Company supplies the QF's electric requirements not met by the QF's own-generating facilities. This also may be referred to as the "parallel mode" of operation.

3. Energy - Electric energy which is supplied by the QF.

4. Firm Capacity - Capacity available, upon demand, at all times (except for forced outages and scheduled maintenance) during the period covered by the Agreement from the QF with an availability factor of at least 80%, as defined by the North American Electric Reliability Council.

5. Net Energy - The total kilowatt hours (kWh) sold to the QF by the company less the total kWhs purchased by the Company from the QF.

6. Supplemental Power - Electric capacity and energy supplied by the Company regularly used by the QF in addition to that which the facility generates itself.

7. Stand-by Power - Electric capacity and energy supplied by the Company to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

8. Maintenance Power - Electric capacity and energy supplied by the Company during scheduled outages of the QF.

9. Purchase Agreement - Agreements for the purchase of electric energy and capacity from and the sale of power to the QF entered into between the Company and QF.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 806-1
Superseding:

RATES FOR SALES TO QFs

Supplemental Service:

A. Service Charge - The service charge shall be the basic service charge using the otherwise applicable retail Rate.

B. Energy Charge - The energy charge shall be the energy charge using the otherwise applicable retail Rate.

C. Demand Charge - The demand charge shall be the demand charge using the otherwise applicable retail Rate and it shall apply only to supplemental power and not to total requirements.

Standby Service:

A. Service Charge - The service charge shall be the basic service charge using the otherwise applicable retail Rate.

B. Energy Charge - The energy charge is $0.[illegible] per kWh per month.

C. Demand Charge - The demand charge shall be the product of $[illegible] per kW per month and the probability (*) that the QF has an unscheduled outage at the time of the company's peak.

(*) This value is initially set at ten percent (10%) for the first year and reset annually based upon actual experience with the QF.

Maintenance Service:

A. Service Charge - The service charge shall be the basic service charge using the otherwise applicable retail Rate.

B. Energy Charge - The energy charge is $0.053845 per kWh per month.

C. Maintenance Service - Must be scheduled with the Company and may only be scheduled during the period October through April.

Only one service charge will be applied for each billing period.

RATES FOR PURCHASES FROM QFs

Basic Service~~Customer~~ charges shall be billed pursuant to the Customer's standard offer tariff otherwise applicable under full requirements of service.

Rates for Firm Capacity purchased from the QF shall be priced at long-run avoided cost based upon deferral of capacity additions indicated in Company's resource plan.

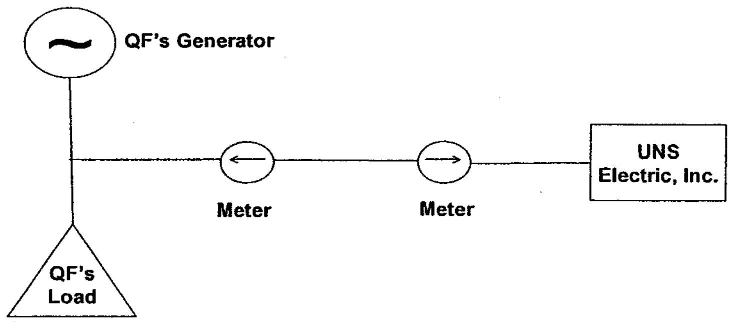
Rates for capacity associated with Firm Capacity shall be as provided for in the Service Agreement.

ADJUSTMENTS

Purchased Power Fuel Adjuster Clause (PPFAC)is a per[illegible] monthly adjustment in accordance with the PPFAC Rider No. 1. The PPFAC reflects any increases or decreases in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. See Rider-1 for current rate.

Filed By:	Kentton C. Grant	Rate:	QF-C
Title:	Vice President	Effective:	~~January 1, 2014~~Pending
District:	Entire Electric Service Area	Decision No.:	~~74235~~Pending

METER CONFIGURATION



CONTRACT PERIOD
As provided for in the Service Agreement.

TERMS AND CONDITIONS
Subject to:

The Service Agreement, and

Shall be interconnected with and can operate in parallel and in phase with the Company's existing distribution system. The Interconnection must comply with the Company's interconnection requirements, and

Shall take service as a Primary Service and Metering Customer (the Company shall not provide voltage transformation on the customer's premise).

A delayed payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rate.

Exhibit CAJ-5

CLEAN

UNS Electric, Inc.

Purchased Power and Fuel Adjustment Clause
Plan of Administration

Table of Contents

1. GENERAL DESCRIPTION

This document describes the plan for administering the Purchased Power and Fuel Adjustment Clause ("PPFAC") the Arizona Corporation Commission ("Commission") approved for UNS Electric, Inc. ("UNS Electric") in Decision No. 74235 (December 31, 2013) as modified in Decision No. XXXXX.

The PPFAC described in this Plan of Administration ("POA") uses a historical twelve (12) month rolling average of actual fuel and purchased power costs to set a rate. The PPFAC rate is adjusted on a monthly basis. This POA describes the application of the PPFAC.

2. DEFINITIONS

Applicable Interest – Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15. The interest rate is adjusted annually on the first business day of the calendar year.

Applicable Twelve (12) Months – The historical 12-month period that ends two months prior to the monthly PPFAC rate change. For example, a January PPFAC rate is based on the 12 months ending November 30.

Base Cost of Fuel and Purchased Power – An amount generally expressed as a rate per kilowatt-hour ("kWh") for each rate class, which reflects the fuel, purchased power and purchased transmission cost embedded in the base rates for each customer class as approved by the Commission in UNS Electric's most recent rate case. The Base Cost of Fuel and Purchased Power revenue is the approved rate per kWh times the applicable sales volumes for each rate class.

Brokerage Fees – The costs attributable to the use of brokers recorded in Federal Energy Regulatory Commission ("FERC") Account 557.

Fuel and Purchased Power Costs – The costs recorded for the fuel and purchased power used by UNS Electric to serve both Native Load Energy Sales and Off-System Sales. Wheeling costs are included.

Native Load Energy Sales – Retail Native Load Energy Sales and Wholesale Native Load Energy Sales in the UNS Electric control area for which UNS Electric has a generation service obligation.

Off-System Sales – Wholesale Sales made to non-Native Load customers, for the purpose of optimizing the UNS Electric system, using UNS Electric-owned or contracted generation and purchased power.

Off-System Sales Revenue – The revenue recorded from wholesale sales made to non-Native Load customers, for the purpose of optimizing the UNS Electric system, using UNS Electric-owned or contracted generation and purchased power.

PPFAC – The Purchased Power and Fuel Adjustment Clause was approved by the Commission in Decision No. 70360, and amended in Decision Nos. 74235 and XXXXX. The PPFAC rate tracks the changes in the cost of obtaining power supplies based upon a historical 12-month rolling average of fuel, purchased power and purchased transmission costs. The PPFAC rate is adjusted monthly. The change in the PPFAC rate is banded, so the new monthly PPFAC rate cannot increase or decrease the Total Average Retail Fuel and Purchased Power Rate by more than 1% from the preceding month's rate, unless authorized by the Commission. Any over or under recovery of actual costs is recorded in the PPFAC bank balance. If the PPFAC bank balance becomes over collected by more than $10 million, UNS Electric must file for a PPFAC rate adjustment within 45 days, or contact Staff to discuss why a PPFAC rate adjustment is not necessary at that time. If the PPFAC bank balance is under collected, the Company has the right to file an application with the ACC requesting a surcharge.

Preference Power – Power allocated to UNS Electric wholesale customers by federal power agencies such as the Western Area Power Administration.

Retail Native Load Energy Sales – The portion of load from Native Load Energy Sales retail customers that are served by UNS Electric.

Short-term Sales – Wholesale sales with a duration of less than one-year made to non-Native Load customers for the purpose of optimizing the UNS Electric system, using UNS Electric owned or contracted generation and purchased power.

Short Term Sales Revenue – The revenue recorded from short term wholesale sales made to non-Native Load customers, for the purpose of optimizing the UNS Electric system, using UNS Electric owned or contracted generation and purchased power.

Total Average Retail Fuel and Purchased Power Rate – The average base cost of fuel and purchased power ($0.xxxx per kWh) plus the appropriate PPFAC rate.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) – Amounts payable to others for the transmission of UNS Electric's electricity over transmission facilities owned by others.

Wholesale Native Load Energy Sales – The portion of load from Native Load Energy Sales wholesale customers that is served by UNS Electric, excluding the load served with Preference Power.

Wholesale Sales – Sales to non-retail customers.

3. CALCULATION OF THE PPFAC RATE

The PPFAC rate (applied as a percentage of base fuel and purchased power rates) is calculated based upon a historical rolling average of fuel and purchased power costs during the Applicable 12-Month period. All revenues from Short-Term Off-System Sales and sales of renewable energy credits that do not flow through the Renewable Energy Standard Tariff will be credited against fuel and purchased power costs. The PPFAC rate shall be reset monthly, beginning the second month new rates are in effect. For example, if new rates are effective January 1, 2016, the PPFAC rate will be 0.0% in the month of January 2016 and a new PPFAC rate will be effective in February 2016 based on the Applicable 12-Month period ending December 31, 2015.

The new PPFAC rate will be effective with the first billing cycle of each month and will not be prorated. The change in the PPFAC rate is banded, so the new PPFAC rate for a month cannot increase or decrease the Total Average Retail Fuel and Purchased Power Rate by more than 1.0% from the prior month's rate. Any over or under recovery of actual costs is recorded in the PPFAC bank balance. The PPFAC rate shall be applied to the customer's bill as a monthly percentage adjustment that is the same for all customer classes.

4. BASE FUEL AND PURCHASED POWER RATE ANNUAL ADJUSTMENT

Each year, beginning with the monthly filing for January 201X, UNS Electric shall calculate the prior year's Base Cost of Fuel and Purchased Power Factor ("Base FPP Rate Factor") and the Base Fuel and Purchased Power Rate Adjustor ("FPP Base FPP Rate Adjustor"). The Base FPP Rate Factor shall be calculated by dividing the prior year's actual Retail Base Fuel and Purchased Power Rate collections by the Base Cost of Fuel and Purchased Power established according to Decision No. XXXXX. The FPP Base Rate Adjustor shall be calculated as [1 / FPP Base Rate Factor].

The Effective Base Fuel and Purchased Power Rate ("Effective Base FPP Rate") will be calculated by multiplying the Base Cost of Fuel and Purchased Power established in Decision No. XXXXX by the Base FPP Rate Adjustor. The Effective Base FPP Rate will be calculated annually and used to calculate the subsequent twelve months' PPFAC rate. For example, the monthly PPFAC filing January 2017 shall use the Effective Base FPP Rate calculated as the Base Cost of Fuel and Purchased Power in Decision No. XXXXX multiplied by the FPP Base Rate Adjustor calculated using actual retail Base Fuel and Purchase Power Revenues collected in from January 2016 through December 2016. Each January, actual retail fuel and purchased power revenues recovered through base rates during the prior 12 months will be used to calculate a new Base FPP Rate Factor, Base FPP Rate Adjustor and Effective Base FPP Rate. The example in Table 1 below illustrates the calculation.

Table 1		Cents/ kwh
Line 1	Actual Base FPP Rate January 2016 – December 2016 (Actual collections divided by GWh load)	.045
Line 2	Average Base FPP Rate approved in Decision No. XXXXX	.050
Line 3	Base FPP Rate Factor (L1/L2)	.900
Line 4	Base FPP Rate Adjustor (1/L3)	1.111
Line 5	2017 Effective FPP Base Rate (L2 x L4)	.0556

The use of the Effective Base FPP Rate does not change the Base Fuel and Purchased Power Rate approved in Decision No. XXXXX, but serves to calibrate the Base Cost of Fuel and Purchased Power with actual collections from customers. The Base FPP Rate Factor illustrates the expected collections based on historical actual collections. Table 2 below illustrates the effect.

Table 2				
2016 Load	Average Base FPP Rate per Decision No. XXXXX	Expected Collections	Actual Collections	Collected Base Rate
GWh	Cents/kwh	$ in ,000s	$ in ,000s	Cents/kwh
1800	.050	$90,000	$81,000	.045
2017 Load	2017 Effective Base FPP Rate	Expected Collections	Actual Collections	Collected Base Rate
1800	.0556	$90,000*	$90,000*	.05
*Note: Actual Collections equal Expected Collections, and the original approved Base FPP Rate per Decision No. XXXX, by calculating [Effective Base FPP Rate x Base FPP Rate Factor x Base FPP Rate Adjustor]. The Base FPP Rate Factor is calculated above.				

5. ***ACCUMULATED PPFAC BANK BALANCE***

UNS Electric shall maintain and report monthly the accumulated PPFAC bank balance. The PPFAC bank balance shall reflect any over or under recovery of actual purchased power and fuel costs compared with the actual amounts recovered through the Base Fuel and Purchased Power and PPFAC rates.

6. *VERIFICATION AND AUDIT*

The amounts charged through the PPFAC will be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent.

7. *SCHEDULES*

The following schedules are attached to this Plan of Administration:

Schedule 1:	Total Average Retail Fuel and Purchased Power Rate Calculation
Schedule 2:	PPFAC Rate Calculation
Schedule 3:	Applicable 12-Month Total Average Fuel Account
Schedule 4:	Surcharge/Credit Calculation
Schedule 5:	Surcharge/Credit Tracking Account
Schedule 6:	Base Fuel and Purchased Power Rate Factor Calculation

8. *COMPLIANCE REPORTS*

UNS Electric shall provide monthly information reports to Commission Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PPFAC. A UNS Electric Officer shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief and that there have been no changes to the Allowable Costs recovered through the PPFAC without Commission approval. These monthly reports shall be due within 45 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The Total Average Retail Fuel and Purchased Power Rate Calculation (Schedule 1) and the PPFAC Rate Calculation (Schedule 2). Additional information will provide other relative inputs and outputs such as:
   a. Total power and fuel costs.
   b. Customer sales in both MWh and thousands of dollars by customer class.
   c. Number of customers by customer class.
   d. A detailed listing of all items excluded from the PPFAC calculations.
   e. A detailed listing of any adjustments to the adjustor reports.
   f. Total off-system sales revenues.
   g. System losses in MWh.
   h. Monthly maximum retail demand in MW.

2. Identification of a contact person and phone number from UNS Electric for questions.

UNS Electric shall also provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 45 days of the end of the reporting period. All of these additional reports must be provided confidentially.

A. Information for each generating unit will include the following items:
   1. Net generation, in MWh per month, and 12 months cumulatively.
   2. Average heat rate, both monthly and 12-month average.
   3. Equivalent forced-outage rate, both monthly and 12-month average.
   4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
   5. Total fuel costs per month.
   6. The fuel cost per kWh per month.

B. Information on power purchases will include the following items per seller (information on economy interchange purchases may be aggregated):
   1. The quantity purchased in MWh.
   2. The demand purchased in MW to the extent specified in the contract.
   3. The total cost for demand to the extent specified in the contract.
   4. The total cost of energy.

C. Fuel purchase information shall include the following items:
   1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.
   2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm, total cost, supply basin, and volume by contract.
   3. Cost of energy purchased from net metered customers at the Commission authorized Renewable Credit Rate.

D. UNS Electric will also provide:
   1. Monthly projections for the next 12-month period showing estimated (Over)/under collected amounts.
   2. A summary of unplanned outage costs by resource type.
   3. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing.
   4. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.

Workpapers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under a fully executed protective agreement. UNS Electric will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PPFAC at any time. Any costs flowed through the PPFAC are subject to refund, if those costs are found to be imprudently incurred.

9. *ALLOWABLE COSTS*

A. Accounts

The allowable PPFAC costs include fuel and purchased power costs incurred to provide service to retail customers. Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PPFAC. The allowable cost components include the following FERC accounts:

- 501 Fuel (Steam)
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)

These accounts are subject to change if the FERC alters its accounting requirements or definitions.

B. Other Allowable Costs

- Brokerage Fees recorded in FERC Account 557

These accounts are subject to change if the FERC alters its accounting requirements or definitions.

Other costs or credits are allowed with approval from the Commission in an Order.

REDLINE

UNS Electric, Inc.

Purchased Power and Fuel Adjustment Clause
Plan of Administration

Table of Contents

1. *GENERAL DESCRIPTION*

This document describes the plan for administering the Purchased Power and Fuel Adjustment Clause ("PPFAC") the Arizona Corporation Commission ("Commission") approved for UNS Electric, Inc. ("UNS Electric") in Decision No. 74235 (December 31, 2013) as modified in Decision No. XXXXX.

The PPFAC described in this Plan of Administration ("POA") uses a historical twelve (12) month rolling average of actual fuel and purchased power costs to set a rate. The PPFAC rate is adjusted on a monthly basis. This POA describes the application of the PPFAC.

2. *DEFINITIONS*

Applicable Interest – Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15. The interest rate is adjusted annually on the first business day of the calendar year.

Applicable Twelve (12) Months – The historical 12-month period that ends two months prior to the monthly PPFAC rate change. For example, a January PPFAC rate is based on the 12 months ending November 30.

Base Cost of Fuel and Purchased Power – ~~For each rate class it is a~~An amount generally expressed as a rate per kilowatt-hour ("kWh") for each rate class, which reflects the fuel, purchased power and purchased transmission cost embedded in the base rates ~~by~~ for each customer class as approved by the Commission in UNS Electric's most recent rate case. The Base Cost of Fuel and Purchased Power revenue is the approved rate per kWh times the applicable sales volumes for each rate class. ~~Decision No. 74235 set the average base cost at \$0.05706 per kWh effective on January 1, 2014.~~

Brokerage Fees – The costs attributable to the use of brokers recorded in Federal Energy Regulatory Commission ("FERC") Account 557.

Fuel and Purchased Power Costs – The costs recorded for the fuel and purchased power used by UNS Electric to serve both Native Load Energy Sales and Off-System Sales. Wheeling costs are included.

Native Load Energy Sales – Retail Native Load Energy Sales and Wholesale Native Load Energy Sales in the UNS Electric control area for which UNS Electric has a generation service obligation.

Off-System Sales – Wholesale Sales made to non-Native Load customers, for the purpose of optimizing the UNS Electric system, using UNS Electric-owned or contracted generation and purchased power.

Off-System Sales Revenue – The revenue recorded from wholesale sales made to non-Native Load customers, for the purpose of optimizing the UNS Electric system, using UNS Electric-owned or contracted generation and purchased power.

PPFAC – The Purchased Power and Fuel Adjustment Clause was approved by the Commission in Decision No. 70360, and amended in Decision Nos. 74235 and XXXXX. The PPFAC rate tracks the changes in the cost of obtaining power supplies based upon a historical 12-month rolling average of fuel, purchased power and purchased transmission costs. The PPFAC rate is adjusted monthly. The change in the PPFAC rate is banded, so the new monthly PPFAC rate cannot increase or decrease the Total Average Retail Fuel and Purchased Power Rate by more than ~~0.83~~1% from the preceding month's rate, unless authorized by the Commission. Any over or under recovery of actual costs is recorded in the PPFAC bank balance. If the PPFAC bank balance becomes over collected by more than $10 million, UNS Electric must file for a PPFAC rate adjustment within 45 days, or contact Staff to discuss why a PPFAC rate adjustment is not necessary at that time. If the PPFAC bank balance is under collected, the Company has the right to file an application with the ACC requesting a surcharge.

Preference Power – Power allocated to UNS Electric wholesale customers by federal power agencies such as the Western Area Power Administration.

Retail Native Load Energy Sales – The portion of load from Native Load Energy Sales retail customers that are served by UNS Electric.

Short-term Sales – Wholesale sales with a duration of less than one-year made to non-Native Load customers for the purpose of optimizing the UNS Electric system, using UNS Electric owned or contracted generation and purchased power.

Short Term Sales Revenue – The revenue recorded from short term wholesale sales made to non-Native Load customers, for the purpose of optimizing the UNS Electric system, using UNS Electric owned or contracted generation and purchased power.

Total Average Retail Fuel and Purchased Power Rate – The average base cost of fuel and purchased power ($0.~~05706~~ xxxx per kWh) plus the appropriate PPFAC rate.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) – Amounts payable to others for the transmission of UNS Electric's electricity over transmission facilities owned by others.

Wholesale Native Load Energy Sales – The portion of load from Native Load Energy Sales wholesale customers that is served by UNS Electric, excluding the load served with Preference Power.

Wholesale Sales – Sales to non-retail customers.

3. CALCULATION OF THE PPFAC RATE

The PPFAC rate (applied as a percentage of base fuel and purchased power rates) is calculated based upon a historical rolling average of fuel and purchased power costs during the Applicable 12-Month period. All revenues from Short-Term Off-System Sales and sales of renewable energy credits that do not flow through the Renewable Energy Standard Tariff will be credited against fuel and purchased power costs. The PPFAC rate shall be reset monthly, beginning the second month new rates are in effect. For example, if new rates are effective January 1, ~~2014~~2016, the PPFAC rate will be ~~$0.0000 per kWh~~0.0% in the month of January ~~2014~~ 2016 and a new PPFAC rate will be effective in February ~~2014~~ 2016 based on the Applicable 12-Month period ending December 31, ~~2013~~2015.

The new PPFAC rate will be effective with the first billing cycle of each month and will not be prorated. The change in the PPFAC rate is banded, so the new PPFAC rate for a month cannot increase or decrease the Total Average Retail Fuel and Purchased Power Rate by more than ~~0.83~~1.0% from the prior month's rate. Any over or under recovery of actual costs is recorded in the PPFAC bank balance. The PPFAC rate shall be applied to the customer's bill as a monthly ~~kWh charge~~percentage adjustment that is the same for all customer classes.

4. BASE FUEL AND PURCHASED POWER RATE ANNUAL ADJUSTMENT

Each year, beginning with the monthly filing for January 201X, UNS Electric shall calculate the prior year's Base Cost of Fuel and Purchased Power Factor ("Base FPP Rate Factor") and the Base Fuel and Purchased Power Rate Adjustor ("FPP Base FPP Rate Adjustor"). The Base FPP Rate Factor shall be calculated by dividing the prior year's actual Retail Base Fuel and Purchased Power Rate collections by the Base Cost of Fuel and Purchased Power established according to Decision No. XXXXX. The FPP Base Rate Adjustor shall be calculated as [1 / FPP Base Rate Factor].

The Effective Base Fuel and Purchased Power Rate ("Effective Base FPP Rate") will be calculated by multiplying the Base Cost of Fuel and Purchased Power established in Decision No. XXXXX by the Base FPP Rate Adjustor. The Effective Base FPP Rate will be calculated annually and used to calculate the subsequent twelve months' PPFAC rate. For example, the monthly PPFAC filing January 2017 shall use the Effective Base FPP Rate calculated as the Base Cost of Fuel and Purchased Power in Decision No. XXXXX multiplied by the FPP Base Rate Adjustor calculated using actual retail Base Fuel and Purchase Power Revenues collected in from January 2016 through December 2016. Each January, actual retail fuel and purchased power revenues recovered through base rates during the prior 12 months will be used to calculate a new Base FPP Rate Factor, Base FPP Rate Adjustor and Effective Base FPP Rate. The example in Table 1 below illustrates the calculation.

Table 1		Cents/ kwh
Line 1	Actual Base FPP Rate January 2016 – December 2016 (Actual collections divided by GWh load)	.045
Line 2	Average Base FPP Rate approved in Decision No. XXXXX	.050
Line 3	Base FPP Rate Factor (L1/L2)	.900
Line 4	Base FPP Rate Adjustor (1/L3)	1.111
Line 5	2017 Effective FPP Base Rate (L2 x L4)	.0556

The use of the Effective Base FPP Rate does not change the Base Fuel and Purchased Power Rate approved in Decision No. XXXXX, but serves to calibrate the Base Cost of Fuel and Purchased Power with actual collections from customers. The Base FPP Rate Factor illustrates the expected collections based on historical actual collections. Table 2 below illustrates the effect.

Table 2				
2016 Load	Average Base FPP Rate per Decision No. XXXXX	Expected Collections	Actual Collections	Collected Base Rate
GWh	Cents/kwh	$ in ,000s	$ in ,000s	Cents/kwh
1800	.050	$90,000	$81,000	.045
2017 Load	2017 Effective Base FPP Rate	Expected Collections	Actual Collections	Collected Base Rate
1800	.0556	$90,000*	$90,000*	.05
*Note: Actual Collections equal Expected Collections, and the original approved Base FPP Rate per Decision No. XXXX, by calculating [Effective Base FPP Rate x Base FPP Rate Factor x Base FPP Rate Adjustor]. The Base FPP Rate Factor is calculated above.				

54. ACCUMULATED PPFAC BANK BALANCE

UNS Electric shall maintain and report monthly the accumulated PPFAC bank balance. The PPFAC bank balance shall reflect any over or under recovery of actual purchased power and fuel costs compared with the actual amounts recovered through the Base Fuel and Purchased Power and PPFAC rates.

6~~5~~. *VERIFICATION AND AUDIT*

The amounts charged through the PPFAC will be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent.

7~~6~~. *SCHEDULES*

The following schedules are attached to this Plan of Administration:

Schedule 1:	Total Average Retail Fuel and Purchased Power Rate Calculation
Schedule 2:	PPFAC Rate Calculation
Schedule 3:	Applicable 12-Month Total Average Fuel Account
Schedule 4:	Surcharge/Credit Calculation
Schedule 5:	Surcharge/Credit Tracking Account
Schedule 6:	Base Fuel and Purchased Power Rate Factor Calculation

8~~7~~. *COMPLIANCE REPORTS*

UNS Electric shall provide monthly information reports to Commission Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PPFAC. A UNS Electric Officer shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief and that there have been no changes to the Allowable Costs recovered through the PPFAC without Commission approval. These monthly reports shall be due within 45 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The Total Average Retail Fuel and Purchased Power Rate Calculation (Schedule 1) and the PPFAC Rate Calculation (Schedule 2). Additional information will provide other relative inputs and outputs such as:
   a. Total power and fuel costs.
   b. Customer sales in both MWh and thousands of dollars by customer class.
   c. Number of customers by customer class.
   d. A detailed listing of all items excluded from the PPFAC calculations.
   e. A detailed listing of any adjustments to the adjustor reports.
   f. Total off-system sales revenues.
   g. System losses in MWh.
   h. Monthly maximum retail demand in MW.

2. Identification of a contact person and phone number from UNS Electric for questions.

UNS Electric shall also provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 45 days of the end of the reporting period. All of these additional reports must be provided confidentially.

A. Information for each generating unit will include the following items:
   1. Net generation, in MWh per month, and 12 months cumulatively.
   2. Average heat rate, both monthly and 12-month average.
   3. Equivalent forced-outage rate, both monthly and 12-month average.
   4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
   5. Total fuel costs per month.
   6. The fuel cost per kWh per month.

B. Information on power purchases will include the following items per seller (information on economy interchange purchases may be aggregated):
   1. The quantity purchased in MWh.
   2. The demand purchased in MW to the extent specified in the contract.
   3. The total cost for demand to the extent specified in the contract.
   4. The total cost of energy.

C. Fuel purchase information shall include the following items:
   1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.
   2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm, total cost, supply basin, and volume by contract.
   3. Cost of energy purchased from net metered customers at the Commission authorized Renewable Credit Rate.

D. UNS Electric will also provide:
   1. Monthly projections for the next 12-month period showing estimated (Over)/under collected amounts.
   2. A summary of unplanned outage costs by resource type.
   3. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing.
   4. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.

Workpapers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under a fully executed protective agreement. UNS Electric will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PPFAC at any time. Any costs flowed through the PPFAC are subject to refund, if those costs are found to be imprudently incurred.

9~~8~~. *ALLOWABLE COSTS*

A. Accounts

The allowable PPFAC costs include fuel and purchased power costs incurred to provide service to retail customers. Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PPFAC. The allowable cost components include the following FERC accounts:

- 501 Fuel (Steam)
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)

These accounts are subject to change if the FERC alters its accounting requirements or definitions.

B. Other Allowable Costs

- Brokerage Fees recorded in FERC Account 557

These accounts are subject to change if the FERC alters its accounting requirements or definitions.

~~No o~~Other costs or credits are allowed with~~out~~ approval from the Commission in an Order.

UNS Electric, Inc.
Purchased Power and Fuel Adjustment Clause
May 2016

Schedule 1	Total Average Retail Fuel and Purchased Power Rate Calculation Effective May 1, 2016 And Projected June 1, 2016
Schedule 2	PPFAC Rate Calculation Effective May 1, 2016 And Projected June 1, 2016
Schedule 3	Applicable 12 month Total Average Fuel Account - (Rate Effective May 1, 2016 And Projected June 1, 2016)
Schedule 4	Base Fuel and Purchased Power Rate Factor Calculation

<u>UNS-Electric Contact Information</u>

Ray Robey (520) 745-3360
Manager, Fuels and Hedging

UNS Electric, Inc.
Purchased Power and Fuel Adjustment Clause
Monthly Confidential Information Filing
May 2016

Schedule 1	Total Average Retail Fuel and Purchased Power Rate Calculation Effective May 1, 2016 And Projected June 1, 2016
Schedule 2	PPFAC Rate Calculation Effective May 1, 2016 And Projected June 1, 2016
Schedule 3	Applicable 12 month Total Average Fuel Account - (Rate Effective May 1, 2016 And Projected June 1, 2016)
Schedule 4	Base Fuel and Purchased Power Rate Factor Calculation

<u>UNS-Electric Contact Information</u>

Ray Robey (520) 745-3360
Manager, Fuels and Hedging

UNS Electric, Inc.
Schedule 1
Total Average Retail Fuel & Purchased Power Rate Calculation Effective May 1, 2016

Line No.	Total Average Retail Fuel and Purchased Power Rate Calculation	Current 1-May-16 [1]	Proposed 1-Jun-16
1	PPFAC % Rate (Sch. 2, L11) [1,4,5]	0%	0%
2	Surcharge/Credit % Rate [2,4,5]	0%	0%
3	Total PPFAC % Rate [4,5] (L1+L2)	0%	0%
4	Average Base Rate[3]	$ -	$ -

Notes:
1 See XXXXX PPFAC Filing and ACC Decision No. XXXXX.
2 A Surcharge/Credit is a figure which may be added/subtracted from the PPFAC Rate should the the Accumulated Bank Balance become less than negative $10 million or greater than $10 million
3 Average Base Rate as determined in ACC Decision No. XXXXX through 12/31/2016 then uses Schedule 4, line 5 amount thereafter.
4 Negative value is PPFAC credit; positive value is PPFAC surcharge.
5 Calculation is percentage of Average Base Rate

UNS Electric, Inc.
Schedule 2
Total Average Retail Fuel & Purchased Power Rate Calculation Effective May 1, 2016
($ in thousands)

Line No.	PPFAC Rate - Calculation	Current 1-May-16[1]	Proposed 1-Jun-16
1	Applicable 12 Months Fuel and Purchased Power Costs [1]	$ -	$ -
2	Applicable 12 Months Short Term Sales Revenue Credit [2]	$ -	$ -
3	Applicable 12 Months Net Fuel and Purchased Power Cost (L1 + L2)	$ -	$ -
4	Applicable 12 Months Total Native Load Energy Sales (MWhs)		
5	Calculated Total Average Retail Costs $/kWh (L3/L4)	$ -	$ -
6	Maximum total average retail cost rate3 ($/kWh for calculation)	$ -	$ -
7	Minimum total average retail cost rate[3] ($/kWh for calculation)	$ -	$ -
8	Calculated total average cost[3] ($/kWh for calculation)	$ -	$ -
9	Average Base Rate[3] (Sch 1, L4, $/kWh)	$ -	$ -
10	Eligible PPFAC collection calculation $/kWh (L8-L9) [3,4]	$ -	$ -
11	PPFAC Rate to be billed as % of Base Rate (L10/L9) [3,4]	0%	0%

Notes:
1 See XXXXX PPFAC Filing and ACC Decision No. XXXXX.
2 Short Term Sales revenues are credited at 100% as approved by the Commission in Decision No. XXXXX.
3 The amounts in "Proposed" column, Lines 6 and 7, will be limited to a +/- 1% change from the amount in the "Current" column, Line 8.
4 Negative value is PPFAC credit; positive value is PPFAC surcharge.

Schedule presentation will appear to roundup $'s and MWhs; however calculations are performed on an actual $ and MWh basis with resultant Rates/kWh roundup to $0.000000/kWh

UNS Electric, Inc.
Schedule 3
Total Average Retail Fuel Account
($ in thousands; PPFAC and Base Rate in $/kWh)
(Negative value is over-collected, Positive value is under-collected)

Line			May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17
1	Prior Month Balance	(L16)																		
1A	Beginning Balance Adjustment (if any)	(L16)																		
1B	Adjusted Beginning Balance	(L16)																		
1C	Total Deferred Savings																			
Energy Sales																				
2	Retail Native Load Energy Sales (MWh)																			
2.5	Retail Native Load Energy Sales Less Community Solar Sales (MWh)																			
3	Retail Native Load Energy Sales including losses (MWh)[1]																			
4	Long Term Energy Sales (MWh)																			
5	Long Term Energy Sales including losses (MWh)[2]																			
6	Total Native Load Energy Sales (MWh)	(L2 + L4)																		
7	Total Native Load Energy Sales including losses (MWh)	(L3 + L5)																		
Fuel and Purchased Power Costs																				
8	Fuel and Purchased Power Costs [3]																			
9	Short Term / Off System Sales Revenue Credit [4]																			
10	Net Fuel and Purchased Power Costs	(L8+L9)																		
Total Retail Fuel and Purchased Power Recovery																				
11	PPFAC Retail Power Supply Costs	(L3 /L7*L10)																		
12	Applicable 12 Months Average Fuel Cost[5]																			
(Over) / Under Collections and Accrued Interest																				
13	(Over)/Under Collections	(L11 -L12)																		
14	Interest[6]	L1*(L19 /12)																		
15	Bank Balance	(L1 + L13 + L14)																		
	Bank Balance Including True-Up																			
16	12-month Average Base Cost of Fuel & Purchased Power - $ per kWh																			
17	Interest Rate (as of 1/1/2016)[7]																			

1 Retail energy losses are the difference between billed retail energy sales and UNS-E's Retail Sales per TEP's control area metering
2 Long Term Energy Sales losses calculated using applicable EHV loss percentage as defined in appropriate OATT.
3 Includes total native load and short term fuel, purchased power and transmission.
4 Includes Short Term Sales Revenue at 100% per Decision XXXXX
5 Applicable 12 Months Avg Fuel Cost is rate which is eligible to be applied each month creating a change equal to or less than a 1% change in Total Retail Rate
6 Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15 on the first business day of the calendar year
7 Interest Rate (as of 1/1/2016)

Schedule presentation will appear to roundup $'s and MWhs; however calculations are performed on an actual $ and MWh basis with resultant Rates/kWh roundup to $0.000000/kWh

Schedule 3

UNS Electric, Inc.
Schedule 4
Base Fuel and Purchased Power Rate Factor Calculation

Line No.	PPFAC Rate - Calculation	(cents per kWh)
1	Actual Base FPP Rate January 2016 – December 2016 (Actual collections divided by GWh load)	
2	Average Base FPP Rate approved in Decision No. XXXXX	
3	Base FPP Rate Factor (L1/L2)	
4	Base FPP Rate Adjustor (L1/L3)	
5	2017 Effective FPP Base Rate (L2 x L4)[1]	

Notes:
1 See XXXXX PPFAC Filing and ACC Decision No. XXXXX.

Schedule presentation will appear to roundup $'s and MWhs; however calculations are performed on an actual $ and MWh basis with resultant Rates/kWh roundup to $0.000000/kWh

Exhibit CAJ-6

CLEAN

UNS Electric, Inc.
Lost Fixed Cost Recovery Mechanism
Plan of Administration

Table of Contents

1. General Description

This document describes the plan of administration for the Lost Fixed Cost Recovery ("LFCR") mechanism approved for UNS Electric, Inc. ("UNS Electric" or "Company") by the Arizona Corporation Commission ("ACC") on xxx xx, xxxx in Decision No. xxxxx. The LFCR mechanism provides for the recovery of lost fixed costs, as measured by a reduction in non-fuel revenue, associated with the amount of energy efficiency ("EE") savings and distributed generation ("DG") that is authorized by the Commission and determined to have occurred. Costs to be recovered through the LFCR include the non-fuel energy costs included in base rates and the demand rates in effect, plus any amount quantified in the Balancing Account.

2. Definitions

Applicable Company Revenues – The amount of revenue generated by sales to retail customers, for all applicable rate schedules.

Balancing Account – A mechanism to track the difference between allowed Lost Fixed Cost Revenue and actual amounts billed by the Company through the LFCR adjustment. The balancing account will be reflected in Schedule 2 of the LFCR Compliance Report and shall be calculated by taking the Total Lost Fixed Cost Revenue from Prior Period less the amount billed through the LFCR for the most recent collection period at the time of filing.

Current Period – The most recent measurement year.

Delivery Revenue – The amount of revenue determined at the conclusion of a rate case by multiplying each participating rate class' adjusted test year billing determinants (kWh or kW) by their approved non-fuel energy and demand charges.

DG Savings – The amount of kWh or kW sales reduced by DG. UNS Electric will use meter data for determining the kWh or kW lost through the implementation of DG systems. Where the meter data is not available, the lost sales will be quantified using statistical verification, output profile or other Commission-authorized methods as appropriate. Each year, UNS Electric will use actual data through December to calculate the savings. The calculation of DG Savings will consist of the following by class:

1. Current Period: The total kWh or kW reduction metered during the measurement year less the total kWh or kW reduction metered in UNS Electric's most recent general rate case test year.
2. The only DG Savings that will be excluded from the Lost Fixed Cost Revenue calculation are those kWh or kW that were lost as the result of actions by customers on the Excluded Rate Schedule.

EE Programs – Any program approved in UNS Electric's Energy Efficiency/Demand Side Management ("EE/DSM") implementation plan or Energy Efficiency Resource Plan.

EE Savings – The amount of sales, expressed in kWh or kW, reduced by Energy Efficiency activities as demonstrated by the Measurement, Evaluation, and Research Report ("MER") conducted for UNS Electric's EE Programs. This process will be a thorough review of the Company's EE activities and will determine the total kWh or kW lost as a result of those activities. As part of this filing the Commission Staff will have the option of reviewing any portion of the filing they deem necessary to verify the filing's accuracy. EE Savings shall be quantified based on the accumulated lost kWh or kW occurring since January 1, 2013, and shall be reset based on EE related losses as of the end of the test year in each rate case. The calculation of EE Savings will consist of the following by class:

1. Current Period: The annual EE related sales reductions (kWh or kW). Each year, UNS Electric will use actual MER data through December to calculate savings.
2. Prior Period: The cumulative total kWh or kW reduction reported in the previous year's LFCR filing, recognizing that the cumulative total is reset (to zero) at the end of each of UNS Electric's most recent rate case. The first such reset will be July 1, 2012, (the end of the Test Year in Decision 74235, dated December 31, 2013). The initial term of the LFCR will begin on January 1, 2013.
3. Excluded kWh reduction: The reduction of recoverable EE Savings calculated by subtracting the amount of EE savings actually achieved by customers on the Excluded Rate Schedule if included in the total reported in the annual EE/DSM filing.

Effective Period – The twelve month period beginning with July 1 of each year.

Excluded Rate Schedule – The LFCR mechanism shall not apply to the lighting rate class.

LFCR Adjustment – An amount calculated by dividing Lost Fixed Cost Revenue by the Applicable Company Revenues. This percentage-based LFCR Adjustment will be applied to all customer bills, excluding those on the Excluded Rate Schedule.

Lost Fixed Cost Rate – A rate determined at the conclusion of a rate case by taking the sum of allowed Delivery Revenue (which excludes the Basic Service Charge and purchased power and fuel) for each rate class and dividing each by their respective class adjusted test year kWh and/or kW billing determinants.

Lost Fixed Cost Revenue – The amount of fixed costs not recovered by the utility because of EE Savings and DG Savings during the measurement period. This amount is calculated by multiplying the Lost Fixed Cost Rate by Recoverable kWh or kW Savings, by rate class.

<u>Prior Period</u> – The twelve months in the calendar year preceding the Current Period.

<u>Recoverable kWh or kW Savings</u> – The EE Savings and DG Savings by applicable rate class.

3. *LFCR Annual Incremental Cap*

The total LFCR Adjustment will be subject to an annual 2% year-over-year cap based on Applicable Company Revenues. If the annual incremental LFCR Adjustment results in a surcharge in excess of 2%, in total, of Applicable Company Revenues, any amount in excess of the 2% cap will be deferred for collection until the next year its inclusion does not result in the 2% year-over-year cap being exceeded. Any deferred amounts, plus any amount quantified in the Balancing Account, will be collected in a subsequent year or rolled into the next rate case, whichever occurs first. Where the 2% cap limits the recovery of deferrals in any program year, and thus moves their recovery to the following year, a first-in, first-out ("FIFO") approach will be applied. In connection therewith, the new surcharge billed in the following year will first recover any such carried-over deferrals, as well as any Balancing Account balance, and then recover new deferrals arising in that following year. The one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15 or its successor publication will be applied annually to any deferred balance. The interest rate shall be adjusted annually and shall be that annual rate applicable to the first business day of the calendar year.

4. *Filing and Procedural Deadlines*

UNS Electric will file the calculated Annual LFCR Adjustment, including all Compliance Reports, with the Commission for the previous year by May 15th. Staff will use its best efforts to process the matter based on the results of the Company's annual EE/DSM and Renewable Energy Standard Tariff ("REST") filings such that the new LFCR Adjustment may go into effect by July 1st of each year. However, the new LFCR Adjustment will not go into effect until approved by the Commission.

5. *Compliance Reports*

UNS Electric will provide comprehensive compliance reports to Staff and the Residential Utility Consumer Office by May 15th of each year. The information contained in the Compliance Reports will consist of the following schedules:

- Schedule 1: LFCR Annual Percentage Adjustment Rate
- Schedule 2: LFCR Annual Incremental Cap Calculation
- Schedule 3: LFCR Calculation
- Schedule 4: LFCR Test Year Rate Calculation
- Schedule 5: Delivery Revenue Calculation

UNS Electric, Inc.
Lost Fixed Cost Recovery Mechanism
Schedule 1: LFCR Annual Percentage Adjustment Rate

Line No.	(A) Annual Percentage Adjustment	(B) Reference		(C) Totals
1	Total Lost Fixed Cost Revenue for Current Period	Schedule 2, Line 15, Column C	$	#DIV/0!
2	20_ _ Applicable Company Revenues	Schedule 2, Line 1, Column C	$	-
3	Percentage Adjustment Applied to Customer's Bills	(Line 1 / Line 2)		0.0000%

UNS Electric, Inc.
Lost Fixed Cost Recovery Mechanism
Schedule 2: LFCR Annual Incremental Cap Calculation

Line No.	(A) LFCR Annual Incremental Cap Calculation	(B) Reference		(C) Totals
1	20_ _ Applicable Company Revenues		$	-
2	Allowed Cap %			2.00%
3	Maximum Allowed Incremental Recovery	(Line 1 * Line 2)	$	-
4	Total Lost Fixed Cost Revenue	Schedule 3, Line 123, Column C	$	#DIV/0!
5	Total Deferred Balance from Previous Period	Previous Filing, Schedule 2, Line 13, Column C	$	-
6	Annual Interest Rate			0.00%
7	Interest Accrued on Deferred Balance	(Line 5 * Line 6)	$	-
8	Total Lost Fixed Cost Revenue Current Period	(Line 4 + Line 5 + Line 7)	$	#DIV/0!
9	Lost Fixed Cost Revenue from Prior Period	Previous Filing, Schedule 2, Line 15, Column C	$	-
10	Lost Fixed Cost Revenue - Billed [1]		$	-
11	LFCR Balancing Account	(Line 9 - Line 10)	$	-
12	Total Incremental Lost Fixed Cost Revenue for Current Year	(Line 8 - Line 9 + Line 11)	$	#DIV/0!
13	Amount in Excess of Cap to Defer	(Line 12 - Line 3)	$	#DIV/0!
14	Incremental Period Adjustment as %	[(Line 12 - Line 13) / Line 1]		0.0000%
15	Total Lost Fixed Cost Revenue for Current Period	(Line 8 + Line 11 - Line 13)	$	#DIV/0!

[1] Amount billed to customers for the collection period of 20_ _

UNS Electric, Inc.
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units
	Residential - Delivery Revenue - Demand				
	Energy Efficiency Savings				
1	Current Period			-	kW
2	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 3, Column C		-	kW
3	Cumulative Recoverable kW savings	(Line 1 + Line 2)		-	kW
4	Total Recoverable EE Savings	Line 3		-	kW
5	Residential - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	#DIV/0!	$/kW
6	Residential - Lost Fixed Cost Revenue Relating to EE	(Line 4 * Line 5)	$	#DIV/0!	
	Distributed Generation				
7	Current Period			-	kW
8	Total Recoverable DG Savings	Line 7		-	kW
9	Residential - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	#DIV/0!	$/kW
10	Residential - Lost Fixed Cost Revenue Relating to DG	(Line 8 * Line 9)	$	#DIV/0!	
	Residential - Delivery Revenue				
	Energy Efficiency Savings				
11	Current Period			-	kWh
12	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 13, Column C		-	kWh
13	Cumulative Recoverable kWh savings	(Line 11 + Line 12)		-	kWh
14	Total Recoverable EE Savings	Line 13		-	kWh
15	Residential - Lost Fixed Cost Rate	Schedule 4, Line 3, Column C	$	#DIV/0!	$/kWh
16	Residential - Lost Fixed Cost Revenue Relating to EE	(Line 14 * Line 15)	$	#DIV/0!	
	Distributed Generation				
17	Current Period			-	kWh
18	Total Recoverable DG Savings	Line 17		-	kWh
19	Residential - Lost Fixed Cost Rate	Schedule 4, Line 3, Column C	$	#DIV/0!	$/kWh
20	Residential - Lost Fixed Cost Revenue Relating to DG	(Line 18 * Line 19)	$	#DIV/0!	
	Small General Service - Delivery Revenue - Demand				
	Energy Efficiency Savings				
21	Current Period			-	kW
22	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 23, Column C		-	kW
23	Cumulative Recoverable kW savings	(Line 21 + Line 22)		-	kW
24	Total Recoverable EE Savings	Line 23		-	kW
25	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	#DIV/0!	$/kW
26	Small General Service - Lost Fixed Cost Revenue Relating to EE	(Line 24 * Line 25)	$	#DIV/0!	
	Distributed Generation				
27	Current Period			-	kW
28	Total Recoverable DG Savings	Line 27		-	kW
29	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	#DIV/0!	$/kW
30	Small General Service - Lost Fixed Cost Revenue Relating to DG	(Line 28 * Line 29)	$	#DIV/0!	

UNS Electric, Inc.
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units
	Small General Service - Delivery Revenue				
	Energy Efficiency Savings				
31	Current Period			-	kWh
32	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 33, Column C		-	kWh
33	Cumulative Recoverable kWh savings	(Line 31 + Line 32)		-	kWh
34	Total Recoverable EE Savings	Line 33		-	kWh
35	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 9, Column C	$	#DIV/0!	$/kWh
36	Small General Service - Lost Fixed Cost Revenue Relating to EE	(Line 34 * Line 35)	$	#DIV/0!	
	Distributed Generation				
37	Current Period			-	kWh
38	Total Recoverable DG Savings	Line 37		-	kWh
39	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 9, Column C	$	#DIV/0!	$/kWh
40	Small General Service - Lost Fixed Cost Revenue Relating to DG	(Line 38 * Line 39)	$	#DIV/0!	
	Medium General Service - Delivery Revenue - Demand				
	Energy Efficiency Savings				
41	Current Period			-	kW
42	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 43, Column C		-	kW
43	Cumulative Recoverable kW savings	(Line 41 + Line 42)		-	kW
44	Total Recoverable EE Savings	Line 43		-	kW
45	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 18, Column C	$	#DIV/0!	$/kW
46	Medium General Service - Lost Fixed Cost Revenue Relating to EE	(Line 44 * Line 45)	$	#DIV/0!	
	Distributed Generation				
47	Current Period			-	kW
48	Total Recoverable DG Savings	Line 47		-	kW
49	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 18, Column C	$	#DIV/0!	$/kW
50	Medium General Service - Lost Fixed Cost Revenue Relating to DG	(Line 48 * Line 49)	$	#DIV/0!	
	Medium General Service - Delivery Revenue				
	Energy Efficiency Savings				
51	Current Period			-	kWh
52	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 53, Column C		-	kWh
53	Cumulative Recoverable kWh savings	(Line 51 + Line 52)		-	kWh
54	Total Recoverable EE Savings	Line 53		-	kWh
55	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 15, Column C	$	#DIV/0!	$/kWh
56	Medium General Service - Lost Fixed Cost Revenue Relating to EE	(Line 54 * Line 55)	$	#DIV/0!	
	Distributed Generation				
57	Current Period			-	kWh
58	Total Recoverable DG Savings	Line 57		-	kWh
59	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 15, Column C	$	#DIV/0!	$/kWh
60	Medium General Service - Lost Fixed Cost Revenue Relating to DG	(Line 58 * Line 59)	$	#DIV/0!	

UNS Electric, Inc.
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units
	Large General Service - Delivery Revenue - Demand				
	Energy Efficiency Savings				
61	Current Period			-	kW
62	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 63, Column C		-	kW
63	Cumulative Recoverable kW savings	(Line 61 + Line 62)		-	kW
64	Total Recoverable EE Savings	Line 63		-	kW
65	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 24, Column C	$	#DIV/0!	$/kW
66	Large General Service - Lost Fixed Cost Revenue Relating to EE	(Line 64 * Line 65)	$	#DIV/0!	
	Distributed Generation				
67	Current Period			-	kW
68	Total Recoverable DG Savings	Line 67		-	kW
69	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 24, Column C	$	#DIV/0!	$/kW
70	Large General Service - Lost Fixed Cost Revenue Relating to DG	(Line 68 * Line 69)	$	#DIV/0!	
	Large General Service - Delivery Revenue				
	Energy Efficiency Savings				
71	Current Period			-	kWh
72	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 73, Column C		-	kWh
73	Cumulative Recoverable kWh savings	(Line 71 + Line 72)		-	kWh
74	Total Recoverable EE Savings	Line 73		-	kWh
75	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 21, Column C	$	#DIV/0!	$/kWh
76	Large General Service - Lost Fixed Cost Revenue Relating to EE	(Line 74 * Line 75)	$	#DIV/0!	
	Distributed Generation				
77	Current Period			-	kWh
78	Total Recoverable DG Savings	Line 77		-	kWh
79	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 21, Column C	$	#DIV/0!	$/kWh
80	Large General Service - Lost Fixed Cost Revenue Relating to DG	(Line 78 * Line 79)	$	#DIV/0!	
	Interruptible Power Service - Delivery Revenue - Demand				
	Energy Efficiency Savings				
81	Current Period			-	kW
82	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 83, Column C		-	kW
83	Cumulative Recoverable kW savings	(Line 81 + Line 82)		-	kW
84	Total Recoverable EE Savings	Line 83		-	kW
85	Interruptible - Lost Fixed Cost Rate	Schedule 4, Line 30, Column C	$	#DIV/0!	$/kW
86	Interruptible - Lost Fixed Cost Revenue Relating to EE	(Line 84 * Line 85)	$	#DIV/0!	
	Distributed Generation				
87	Current Period			-	kW
88	Total Recoverable DG Savings	Line 87		-	kW
89	Interruptible - Lost Fixed Cost Rate	Schedule 4, Line 30, Column C	$	#DIV/0!	$/kW
90	Interruptible - Lost Fixed Cost Revenue Relating to DG	(Line 88 * Line 89)	$	#DIV/0!	

UNS Electric, Inc.
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units
	Interruptible Power Service - Delivery Revenue				
	Energy Efficiency Savings				
91	Current Period			-	kWh
92	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 93, Column C		-	kWh
93	Cumulative Recoverable kWh savings	(Line 91 + Line 92)		-	kWh
94	Total Recoverable EE Savings	Line 93		-	kWh
95	Interruptible - Lost Fixed Cost Rate	Schedule 4, Line 27, Column C	$	#DIV/0!	$/kWh
96	Interruptible - Lost Fixed Cost Revenue Relating to EE	(Line 94 * Line 95)	$	#DIV/0!	
	Distributed Generation				
97	Current Period			-	kWh
98	Total Recoverable DG Savings	Line 97		-	kWh
99	Interruptible - Lost Fixed Cost Rate	Schedule 4, Line 27, Column C	$	#DIV/0!	$/kWh
100	Interruptible - Lost Fixed Cost Revenue Relating to DG	(Line 98 * Line 99)	$	#DIV/0!	
	Large Power Service - Delivery Revenue - Demand				
	Energy Efficiency Savings				
101	Current Period				kW
102	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 103, Column C		-	kW
103	Cumulative Recoverable kW savings	(Line 101 + Line 102)		-	kW
104	Total Recoverable EE Savings	Line 103		-	kW
105	Large Power Service - Lost Fixed Cost Rate	Schedule 4, Line 36, Column C	$	#DIV/0!	$/kW
106	Large Power Service - Lost Fixed Cost Revenue Relating to EE	(Line 104 * Line 105)	$	#DIV/0!	
	Distributed Generation				
107	Current Period			-	kW
108	Total Recoverable DG Savings	Line 107		-	kW
109	Large Power Service - Lost Fixed Cost Rate	Schedule 4, Line 36, Column C	$	#DIV/0!	$/kW
110	Large Power Service - Lost Fixed Cost Revenue Relating to DG	(Line 108 * Line 109)	$	#DIV/0!	
	Large Power Service - Delivery Revenue				
	Energy Efficiency Savings				
111	Current Period			-	kWh
112	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 113, Column C		-	kWh
113	Cumulative Recoverable kWh savings	(Line 111 + Line 112)		-	kWh
114	Total Recoverable EE Savings	Line 113		-	kWh
115	Large Power Service - Lost Fixed Cost Rate	Schedule 4, Line 33, Column C	$	#DIV/0!	$/kWh
116	Large Power Service - Lost Fixed Cost Revenue Relating to EE	(Line 114 * Line 115)	$	#DIV/0!	
	Distributed Generation				
117	Current Period			-	kWh
118	Total Recoverable DG Savings	Line 117		-	kWh
119	Large Power Service - Lost Fixed Cost Rate	Schedule 4, Line 33, Column C	$	#DIV/0!	$/kWh
120	Large Power Service - Lost Fixed Cost Revenue Relating to DG	(Line 118 * Line 119)	$	#DIV/0!	
121	Total Lost Fixed Cost Revenue Related to Energy Efficiency	Sum Line 6 + 16 + 26 + 36 + 46 + 56 + 66 + 76 + 86 + 96 + 106 + 116	$	#DIV/0!	
122	Total Lost Fixed Cost Revenue Related to Distributed Generation	Sum Line 10 + 20 + 30 + 40 + 50 + 60 + 70 + 80 + 90 + 100 + 110 + 120	$	#DIV/0!	
123	Total Lost Fixed Cost Revenue	(Line 121 + Line 122)	$	#DIV/0!	

UNS Electric, Inc.
Lost Fixed Cost Recovery Mechanism
Schedule 4: LFCR Test Year Rate Calculation

Line No.	(A) LFCR Fixed Cost Calculation		(B) Reference		(C) Totals
	Residential Customers				
1		Delivery Revenue	Schedule 5, Line 7, Column E	$	-
2		kWh Billed	Schedule 5, Line 7, Column B		-
3		Lost Fixed Cost Rate	(Line 1 / Line 2)	$	#DIV/0!
	Residential Customers				
4		Delivery Revenue - Demand	Schedule 5, Line 29, Column E	$	-
5		kW Billed	Schedule 5, Line 29, Column B		-
6		Lost Fixed Cost Rate	(Line 4 / Line 5)	$	#DIV/0!
	Small General Service				
7		Delivery Revenue	Schedule 5, Line 12, Column E	$	-
8		kWh Billed	Schedule 5, Line 12, Column B		-
9		Lost Fixed Cost Rate	(Line 7 / Line 8)	$	#DIV/0!
	Small General Service				
10		Delivery Revenue - Demand	Schedule 5, Line 32, Column E	$	-
11		kW Billed	Schedule 5, Line 32, Column B		-
12		Lost Fixed Cost Rate	(Line 10 / Line 11)	$	#DIV/0!
	Medium General Service				
13		Delivery Revenue	Schedule 5, Line 16, Column E	$	-
14		kWh Billed	Schedule 5, Line 16, Column B		-
15		Lost Fixed Cost Rate	(Line 13 / Line 14)	$	#DIV/0!
	Medium General Service				
16		Delivery Revenue - Demand	Schedule 5, Line 36, Column E	$	-
17		kW Billed	Schedule 5, Line 36, Column B		-
18		Lost Fixed Cost Rate	(Line 16 / Line 17)	$	#DIV/0!
	Large General Service				
19		Delivery Revenue	Schedule 5, Line 20, Column E	$	-
20		kWh Billed	Schedule 5, Line 20, Column B		-
21		Lost Fixed Cost Rate	(Line 19 / Line 20)	$	#DIV/0!
	Large General Service				
22		Delivery Revenue - Demand	Schedule 5, Line 40, Column E	$	-
23		kW Billed	Schedule 5, Line 40, Column B		-
24		Lost Fixed Cost Rate	(Line 22 / Line 23)	$	#DIV/0!
	Interruptible Power Service				
25		Delivery Revenue	Schedule 5, Line 22, Column E	$	-
26		kWh Billed	Schedule 5, Line 22, Column B		-
27		Lost Fixed Cost Rate	(Line 25 / Line 26)	$	#DIV/0!
	Interruptible Power Service				
28		Delivery Revenue - Demand	Schedule 5, Line 42, Column E	$	-
29		kW Billed	Schedule 5, Line 42, Column B		-
30		Lost Fixed Cost Rate	(Line 28 / Line 29)	$	#DIV/0!
	Large Power Service				
31		Delivery Revenue	Schedule 5, Line 25, Column E	$	-
32		kWh Billed	Schedule 5, Line 25, Column B		-
33		Lost Fixed Cost Rate	(Line 31 / Line 32)	$	#DIV/0!
	Large Power Service				
34		Delivery Revenue - Demand	Schedule 5, Line 45, Column E	$	-
35		kW Billed	Schedule 5, Line 45, Column B		-
36		Lost Fixed Cost Rate	(Line 34 / Line 35)	$	#DIV/0!

UNS Electric, Inc.
Lost Fixed Cost Recovery Mechanism
Schedule 5: Delivery Revenue Calculation

Line No.	(A) Rate Schedule	(B) Adjusted Test Year Billing Determinants	(C) Units	(D) Delivery Charge	(E) B x D Total Delivery Revenue
	kWh related				
1	Residential Service (RES-01)		kWh	$	$ -
2	Residential Service (RES-01 TOU)		kWh	$	$ -
3	Residential Service (RES-01 TOU SuperPeak)		kWh	$	$ -
4	Residential Service (CARES)		kWh	$	$ -
5	Residential Service (RES-01 Demand)		kWh	$	$ -
6	Residential Service (RES-01 Demand TOU)		kWh	$	$ -
7	Subtotal - kWh	-	kWh		$ -
8	Small General Service (SGS-10)		kWh	$	$ -
9	Small General Service (SGS-10 TOU)		kWh	$	$ -
10	Small General Service (SGS-10 Demand)		kWh	$	$ -
11	Small General Service (SGS-10 Demand TOU)		kWh	$	$ -
12	Subtotal - kWh	-	kWh		$ -
13	Medium General Service (MGS)		kWh	$	$ -
14	Medium General Service (MGS-TOU)		kWh	$	$ -
15	Medium General Service (MGS-TOU-S)		kWh	$	$ -
16	Subtotal - kWh	-	kWh		$ -
17	Large General Service (LGS)		kWh	$	$ -
18	Large General Service (LGS-TOU)		kWh	$	$ -
19	Large General Service (LGS-TOU-S)		kWh	$	$ -
20	Subtotal - kWh	-	kWh		$ -
21	Interruptible Power Service (IPS)		kWh	$	$ -
22	Subtotal - kWh	-	kWh		$ -
23	Large Power Service (LPS)		kWh	$	$ -
24	Large Power Service (LPS-TOU)		kWh	$	$ -
25	Subtotal - kWh	-	kWh		$ -
26	Total kWh	-	kWh		$ -
	kW related				
27	Residential Service (RES-01 Demand)		kW	$	$ -
28	Residential Service (RES-01 Demand TOU)		kW	$	$ -
29	Subtotal - kW	-	kW		$ -
30	Small General Service (SGS-10 Demand)		kW	$	$ -
31	Small General Service (SGS-10 Demand TOU)		kW	$	$ -
32	Subtotal - kW	-	kW		$ -
33	Medium General Service (MGS)		kW	$	$ -
34	Medium General Service (MGS-TOU)		kW	$	$ -
35	Medium General Service (MGS-TOU-S)		kW	$	$ -
36	Subtotal - kW	-	kW		$ -
37	Large General Service (LGS)		kW	$	$ -
38	Large General Service (LGS-TOU)		kW	$	$ -
39	Large General Service (LGS-TOU-S)		kW	$	$ -
40	Subtotal - kW	-	kW		$ -
41	Interruptible Power Service (IPS)		kW	$	$ -
42	Subtotal - kW	-	kW		$ -
43	Large Power Service (LPS)		kW	$	$ -
44	Large Power Service (LPS-TOU)		kW	$	$ -
45	Subtotal - kW	-	kW		$ -
46	Total kW	-	kW		$ -

REDLINE

UNS Electric, Inc.
Lost Fixed Cost Recovery Mechanism
Plan of Administration

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1. General Description

This document describes the plan of administration for the Lost Fixed Cost Recovery ~~Mechanism~~ ("LFCR") mechanism approved for UNS Electric, Inc. ("UNS Electric" or "Company") by the Arizona Corporation Commission ("ACC") on xxx xx, xxxx~~December 31, 2013~~ in Decision No. xxxxx~~74235~~. The LFCR mechanism provides for the recovery of lost fixed costs, as measured by a reduction in non-fuel revenue, associated with the amount of energy efficiency ("EE") savings and distributed generation ("DG") that is authorized by the Commission and determined to have occurred. Costs to be recovered through the LFCR include the ~~portion of transmission and distribution~~non-fuel energy costs included in base rates ~~exclusive of the Customer Charge~~ and ~~50% of~~ the demand rates in effect, plus any amount quantified in the Balancing Account.

2. *Definitions*

Applicable Company Revenues – The amount of revenue generated by sales to retail customers, for all applicable rate schedules~~. less the amount attributable to sales to those residential customers who chose the Fixed Cost Option~~.

Balancing Account – A mechanism to track the difference between allowed Lost Fixed Cost Revenue and actual amounts billed by the Company through the LFCR adjustment. The balancing account will be reflected in Schedule 2 of the LFCR Compliance Report and shall be calculated by taking the Total Lost Fixed Cost Revenue from Prior Period less the amount billed through the LFCR for the most recent collection period at the time of filing.

Current Period – The most recent ~~adjustment~~ measurement year.

~~Demand Stability Factor – Fifty percent of Demand-based revenue (excluding any purchased power and fuel costs) produced by base rates.~~

Delivery Revenue – The amount of revenue determined at the conclusion of a rate case by multiplying each participating rate class' adjusted test year billing determinants (kWh or kW) by their approved non-fuel energy and demand ~~distribution and transmission related~~ charges. ~~This~~

~~will be determined by reducing each class' total retail revenue by the customer charge, generation related revenue, purchased power and fuel costs and the Demand Stability Factor.~~

~~Distributed Generation ("DG")~~<u>DG Savings</u> – The amount of kWh or kW sales reduced by DG. UNS Electric will use meter data for determining the kWh or kW lost through the implementation of DG systems. Where the meter data is not available, the lost sales will be quantified using statistical verification, output profile or other Commission-authorized methods as appropriate. Each year, UNS Electric will use actual data through December to calculate the savings. The calculation of DG ~~s~~Savings will consist of the following by class:

1. ~~Cumulative Verified~~ Period: The total kWh or kW reduction ~~as~~ metered ~~each year~~during the measurement year less the total kWh or kW reduction metered in UNS Electric's most recent general rate case test year~~(July 1, 2011 through June 30, 2012)~~. ~~The initial Cumulative Verified term of the LFCR will begin on January 1, 2013.~~

~~2. Current Period: The annual kWh or kW produced by the cumulative total of DG installations since the end of the test year used in UNS Electric's most recent general rate case.~~

2. The only DG Savings that will be excluded from the~~calculated~~ Lost Fixed Cost Revenue calculation are those kWh or kW that were lost as the result of actions by customers on~~in~~ the E~~e~~xcluded R~~r~~ate Schedule~~classes or that chose the Fixed Cost Option~~.

~~Fixed Cost Option – The rate schedule choice for residential customers who prefer contributing to the recovery of Lost Fixed Cost Revenue in the form of an optional fixed rate added as an incremental charge to the Customer Charge in the applicable residential tariff rate. The total dollars paid as an incremental amount added to the otherwise effective Customer Charge will be accumulated over the Current Period and used to reduce the total Lost Fixed Cost Revenue recovered as part of the LFCR adjustment. The variable LFCR adjustment shall not be applied to residential customers who choose the Fixed Cost option. This rate will be reflected as an incremental addition to the customer charge on the otherwise effective tariff and made available to customers at the time of the first LFCR adjustment. Customers choosing this fixed option within the first twelve months subsequent to the initial effective date of the LFCR will be allowed to change back to the volumetric option one time without any penalties. After the initial twelve month period customer will be required to stay on whichever option they choose for twelve full months before a change can be made.~~

<u>EE Programs</u> – Any program approved in UNS Electric's Energy Efficiency/Demand Side Management ("EE/DSM") implementation plan or Energy Efficiency Resource Plan.

<u>EE Savings</u> – The amount of sales, expressed in kWh or kW, reduced by Energy Efficiency activities as demonstrated by the Measurement, Evaluation, and Research Report ("MER") conducted for UNS Electric's EE Programs. ~~Since~~ T~~t~~his process will be a thorough review of the Company's EE activities and will determine the total kWh or kW lost as a result of those activities. As part of this filing the Commission Staff will have the option of reviewing any portion of the filing they deem necessary to verify the filing's accuracy. EE Savings shall be quantified based on the accumulated lost kWh or kW occurring since January 1, 2013, and shall be reset based on EE related losses as of the end of the test year in each~~subsequent~~ rate case. The calculation of EE Savings will consist of the following by class:

1. Current Period: The annual EE related sales reductions (kWh or kW). Each year, UNS Electric will use actual MER data through December to calculate savings.

2~~1~~. ~~Cumulative Verified~~Prior Period: The cumulative total kWh or kW reduction ~~as~~ reported in the previous year's LFCR filing~~determined by the MER~~, recognizing that the cumulative total is reset (to zero) at the end of each of UNS Electric's most recent rate case. The first such reset will be July 1, 2012, (the end of the Test Year in Decision 74235, dated December 31, 2013). The initial ~~Cumulative Verified~~ term of the LFCR will begin on January 1, 2013.

~~2. Current Period: The annual EE related sales reductions (kWh or kW). Each year. UNS Electric will use actual MER data through December to calculate savings.~~

3. Excluded kWh reduction: The reduction of recoverable EE Savings calculated by subtracting the amount of EE savings actually achieved by customers on the Excluded Rate Schedule if included in the total reported in the annual EE/DSM filing.

Effective Period – The twelve month period beginning with July 1 of each year.

Excluded Rate Schedule – The LFCR mechanism shall not apply to the lighting rate class.

LFCR Adjustment – An amount calculated by dividing Lost Fixed Cost Revenue ~~(As reduced by the total incremental fixed cost option dollars paid by the residential customers who have chosen the Fixed Cost Option and will be based on the incremental increase in the customer charge they have paid over the twelve months during the Current Period.)~~ by the Applicable Company Revenues.~~Current Period retail revenue (less the estimated sales to the residential customers who chose the Fixed Cost Option) during the Effective Period for the participating rate classes. This percentage based LFCR Adjustment will be presented on the customer's bills as two separate charges. These two charges will be developed by applying the weighted average proportion of the Energy Efficiency related lost revenues and the Distributed Generation related lost revenues as a proportion of total lost revenues falling under the 1% cap referenced herein. The weighted average proportions will be as shown on Schedule 3 of this Plan of Administration. These two separate percentage adjustment rates~~ This percentage-based LFCR Adjustment will be applied to all customer bills, excluding those on the Excluded Rate Schedule~~s~~.

Lost Fixed Cost Rate – A rate determined at the conclusion of a rate case by taking the sum of allowed Delivery Revenue (which excludes the ~~Customer~~Basic Service Charge~~, the generation component in rates~~ and purchased power and fuel) for each rate class and dividing each by their respective class adjusted test year kWh and/or kW billing determinants.

Lost Fixed Cost Revenue – The amount of fixed costs not recovered by the utility because of EE Savings and DG Savings during the measurement period. This amount is calculated by multiplying the Lost Fixed Cost Rate by Recoverable kWh or kW Savings, by rate class.

Prior Period – The twelve months in the calendar year preceding the Current Period.

Recoverable kWh or kW Savings – The ~~sum of~~ EE Savings and DG Savings by applicable rate class.

3. ***LFCR Annual Incremental Cap***

The total LFCR Adjustment will be subject to an annual ~~1~~2% year-over-year cap based on Applicable Company Revenues. If the annual incremental LFCR Adjustment results in a surcharge in excess of ~~1~~2%, in total, of Applicable Company Revenues, any amount in excess of the ~~1~~2% cap will be deferred for collection until the next year its inclusion does not result in the ~~1~~2% year-over-year cap being exceeded. Any deferred amounts, plus any amount quantified in the Balancing Account, will be collected in a subsequent year or rolled into the next rate case, whichever occurs first. Where the ~~1~~2% cap limits the recovery of deferrals in any program year, and thus moves their recovery to the following year, a first-in, first-out ("FIFO") approach will be applied. In connection therewith, the new surcharge billed in the following year will first recover any such carried-over deferrals, as well as any Balancing Account balance, and then recover new deferrals arising in that following year. The one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15 or its successor publication will be applied annually to any deferred balance. The interest rate shall be adjusted annually and shall be that annual rate applicable to the first business day of the calendar year.

4. ***Filing and Procedural Deadlines***

UNS Electric will file the calculated Annual LFCR Adjustments, including all Compliance Reports, with the Commission for the previous year by May 15th. Staff will use its best efforts to process the matter based on the results of the Company's annual EE/DSM and Renewable Energy Standard Tariff ("REST") filings such that the new LFCR Adjustments may go into effect by July 1st of each year. However, the new LFCR Adjustments will not go into effect until approved by the Commission.

5. ***Compliance Reports***

UNS Electric will provide comprehensive compliance reports to Staff and the Residential Utility Consumer Office by May 15th of each year. The information contained in the Compliance Reports will consist of the following schedules:

- Schedule 1: LFCR Annual Percentage Adjustment Rate
- Schedule 2: LFCR Annual Incremental Cap Calculation
- Schedule 3: LFCR Calculation
- Schedule 4: LFCR Test Year Rate Calculation
- Schedule 5: Delivery Revenue Calculation

UNS Electric, Inc.
Lost Fixed Cost Recovery Mechanism
Schedule 1: LFCR Annual Percentage Adjustment Rates

Line No.	(A) Annual Percentage Adjustment	(B) Reference		(C) Totals
	~~Energy Efficiency Related Adjustment~~			
1	Total Lost Fixed Cost Revenue for Current Period	Schedule 2, Line 15, Column C [illegible] ~~Sch 3, Line 104, Col E)~~	$	#DIV/0!
2	20_ _ Applicable Company Revenues	Schedule 2, Line 1, Column C	$	-
3	Percentage Adjustment Applied to Customer's Bills ~~for EE~~	(Line 1 / Line 2)		0.0000%
	~~Distributed Generation Related Adjustment~~			
~~4~~	~~Total Lost Fixed Cost Revenue for Current Period~~	~~(Sch 2, Line 15, Col C - Sch 3, Line 104, Col E)~~	~~$~~	~~#DIV/0!~~
~~5~~	~~20_ _ Applicable Company Revenues~~	~~Schedule 2, Line 1, Column C~~	~~$~~	
~~6~~	~~Percentage Adjustment Applied to Customer's Bills for DG~~	~~(Line 4 / Line 5)~~		~~0.0000%~~

UNS Electric, Inc.
Lost Fixed Cost Recovery Mechanism
Schedule 2: LFCR Annual Incremental Cap Calculation

Line No.	(A) LFCR Annual Incremental Cap Calculation	(B) Reference		(C) Totals
1	20_ _ Applicable Company Revenues		$	-
2	Allowed Cap %			2% ~~1%~~
3	Maximum Allowed Incremental Recovery	(Line 1 * Line 2)	$	#VALUE!
4	Total Lost Fixed Cost Revenue	Schedule 3, Line 123, Column C	$	#DIV/0!
5	Total Deferred Balance from Previous Period	Previous Filing, Schedule 2, Line 13, Column C	$	-
6	Annual Interest Rate			0.00%
7	Interest Accrued on Deferred Balance	(Line 5 * Line 6)	$	-
8	Total Lost Fixed Cost Revenue Current Period	(Line 4 + Line 5 + Line 7)	$	#DIV/0!
9	Lost Fixed Cost Revenue from Prior Period	Previous Filing, Schedule 2, Line 15, Column C	$	-
10	Lost Fixed Cost Revenue - Billed [1]		$	-
11	LFCR Balancing Account	(Line 9 - Line 10)	$	-
12	Total Incremental Lost Fixed Cost Revenue for Current Year	(Line 8 - Line 9 + Line 11)	$	#DIV/0!
13	Amount in Excess of Cap to Defer	(Line 12 - Line 3)	$	#DIV/0!
14	Incremental Period Adjustment as %	[(Line 12 - Line 13) / Line 1]		0.0000%
15	Total Lost Fixed Cost Revenue for Current Period	(Line 8 + Line 11 - Line 13)	$	#DIV/0!

[1] Amount billed to customers for the collection period of 20_ _

UNS Electric, Inc.
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units
	Residential - Delivery Revenue - Demand				
	Energy Efficiency Savings				
1	Current Period			-	kW
2	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 3, Column C		-	kW
3	Cumulative Recoverable kW savings	(Line 1 + Line 2)		-	kW
4	Total Recoverable EE Savings	Line 3		-	kW
5	Residential - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	#DIV/0!	$/kW
6	Residential - Lost Fixed Cost Revenue Relating to EE	(Line 4 * Line 5)	$	#DIV/0!	
	Distributed Generation				
7	Current Period			-	kW
8	Total Recoverable DG Savings	Line 7		-	kW
9	Residential - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	#DIV/0!	$/kW
10	Residential - Lost Fixed Cost Revenue Relating to DG	(Line 8 * Line 9)	$	#DIV/0!	
	Residential - Delivery Revenue				
	Energy Efficiency Savings				
11	**Current Period**			-	**kWh**
~~12~~	~~% of Residential Customers choosing fixed option~~			~~0.0%~~	
~~13~~	~~Excluded kWh reduction~~	~~(Line 1 * Line 2)~~			~~kWh~~
~~14~~	~~Net - Current Period~~	~~(Line 1 - Line 2)~~			~~kWh~~
12	**Prior Period kWh EE losses**	**Previous Filing, Schedule 3, Line 13, Column C**		-	**kWh**
	Cumulative Recoverable kWh savings	~~(Previous Filing, Schedule 3, Line 6, Column C~~ **Line** 11 + Line 12)		-	**kWh**
	Total Recoverable EE Savings	**Line**		-	**kWh**
	Residential - Lost Fixed Cost Rate	**Schedule 4, Line 3, Column C**	**$**	**#DIV/0!**	**$/kWh**
	Residential - Lost Fixed Cost Revenue Relating to EE	**(Line * Line)**	**$**	**#DIV/0!**	
	Distributed Generation				
	Current Period			-	**kWh**
	~~Total Residential kWh reduction~~			~~0.0%~~	
	~~Excluded kWh reduction~~	~~(Line 16 * Line 17)~~			~~kWh~~
	~~Net - Current Period~~	~~(Line 16 - Line 17)~~			~~kWh~~
	~~Prior Period kWh DG losses~~	~~Previous Filing, Schedule 3, Line 15, Column C~~			~~kWh~~
	~~Cumulative Recoverable kWh savings~~	~~(Previous Filing, Schedule 3, Line 15, Column C + Line 14)~~			~~kWh~~
18	**Total Recoverable DG Savings**	**Line 17**		-	**kWh**
19	**Residential - Lost Fixed Cost Rate**	**Schedule 4, Line 3, Column C**	**$**	**#DIV/0!**	**$/kWh**
20	**Residential - Lost Fixed Cost Revenue Relating to DG**	**(Line 18 * Line 19)**	**$**	**#DIV/0!**	
	Small General Service - Delivery Revenue - Demand				
	Energy Efficiency Savings				
21	Current Period			-	kW
22	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 23, Column C		-	kW
23	Cumulative Recoverable kW savings	(Line 21 + Line 22)			kW
24	Total Recoverable EE Savings	Line 23		-	kW
25	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	#DIV/0!	$/kW
26	Small General Service - Lost Fixed Cost Revenue Relating to EE	(Line 24 * Line 25)	$	#DIV/0!	
	Distributed Generation				
27	Current Period			-	kW
28	Total Recoverable DG Savings	Line 27			kW
29	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C			
30	[illegible]	[illegible]			

UNS Electric, Inc.
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units	(E) Weighting
	Small General Service - Delivery Revenue					
	Energy Efficiency Savings					
31	Current Period			-	kWh	
32	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 33, Column C		-	kWh	
	Cumulative Recoverable kWh savings	([illegible] Line [illegible])		-	kWh	
	Total Recoverable EE Savings	Line [illegible]		-	kWh	
	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line [illegible], Column C	$	#DIV/0!	$/kWh	
	Small General Service - Lost Fixed Cost Revenue Relating to EE	(Line [illegible] * Line [illegible])	$	#DIV/0!		
	Distributed Generation					
37	Current Period			-	kWh	
[illegible]	~~Prior Period kWh DG losses~~	~~Previous Filing, Schedule [illegible], Line [illegible], Column C~~			~~kWh~~	
[illegible]	~~Cumulative Recoverable kWh savings~~	~~(Previous Filing, Schedule 3, Line [illegible], Column C + Line [illegible])~~			~~kWh~~	
38	**Total Recoverable DG Savings**	**Line 37**		-	kWh	
39	**Small General Service - Lost Fixed Cost Rate**	**Schedule 4, Line 9, Column C**	$	#DIV/0!	$/kWh	
40	**Small General Service - Lost Fixed Cost Revenue Relating to DG**	**(Line 38 * Line 39)**	$	#DIV/0!		
	Medium General Service - Delivery Revenue - Demand					
	Energy Efficiency Savings					
41	Current Period			-	kW	
42	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 43, Column C		-	kW	
43	Cumulative Recoverable kW savings	(Line 41 + Line 42)			kW	
44	Total Recoverable EE Savings	Line 43		-	kW	
45	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	#DIV/0!	$/kW	
46	Medium General Service - Lost Fixed Cost Revenue Relating to EE	(Line 44 * Line 45)	$	#DIV/0!		
	Distributed Generation					
47	Current Period				kW	
48	Total Recoverable DG Savings	Line 47		-	kW	
49	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	#DIV/0!	$/kW	
50	Medium General Service - Lost Fixed Cost Revenue Relating to DG	(Line 48 * Line 49)	$	#DIV/0!		
	Medium General Service - Delivery Revenue					
	[illegible]					
[illegible]	[illegible]				[illegible]	
[illegible]	[illegible]	[illegible]			[illegible]	
[illegible]	[illegible]	[illegible]			[illegible]	
[illegible]	Total Recoverable EE Savings	[illegible]			kWh	
[illegible]	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 15, Column C	$	#DIV/0!	$/kWh	
[illegible]	Medium General Service - Lost Fixed Cost Revenue Relating to EE	(Line 54 * Line 55)	$	#DIV/0!		
	Distributed Generation					
57	Current Period			-	kWh	
58	Total Recoverable DG Savings	Line 57		-	kWh	
59	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 15, Column C	$	#DIV/0!	$/kWh	
60	Medium General Service - Lost Fixed Cost Revenue Relating to DG	(Line 58 * Line 59)	$	#DIV/0!		

UNS Electric, Inc.
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units
	Large General Service - Delivery Revenue - Demand				
	Energy Efficiency Savings				
61	Current Period			-	kW
62	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 63, Column C		-	kW
63	Cumulative Recoverable kW savings	~~(Previous Filing, Schedule 3, Line [illegible], Column C~~ Line 61 + Line 62)		-	kW
64	Total Recoverable EE Savings	Line 63		-	kW
65	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line [illegible], Column C	$	#DIV/0!	$/kW
66	Large General Service - Lost Fixed Cost Revenue Relating to EE	(Line 64 * Line 65)	$	#DIV/0!	
	Distributed Generation				
67	Current Period			-	kW
[illegible]	~~Prior Period kW DG losses~~	~~Previous Filing, Schedule 3, Line [illegible], Column C~~			~~kW~~
[illegible]	~~Cumulative Recoverable kW savings~~	~~(Previous Filing, Schedule 3, Line [illegible], Column C Line [illegible])~~			~~kW~~
[illegible]	Total Recoverable DG Savings	Line 67		-	kW
[illegible]	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line [illegible], Column C	$	#DIV/0!	$/kW
[illegible]	Large General Service - Lost Fixed Cost Revenue Relating to DG	(Line [illegible] * Line [illegible])	$	#DIV/0!	
	Large General Service - Delivery Revenue				
	Energy Efficiency Savings				
	Current Period			-	kWh
	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line [illegible], Column C			kWh
[illegible]	Cumulative Recoverable kWh savings	~~(Previous Filing, Schedule 3, Line [illegible], Column C~~ Line [illegible] + Line [illegible])		-	kWh
74	Total Recoverable EE Savings	Line [illegible]		-	kWh
75	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 21, Column C	$	#DIV/0!	$/kWh
76	Large General Service - Lost Fixed Cost Revenue Relating to EE	(Line 74 * Line 75)	$	#DIV/0!	
	Distributed Generation				
77	Current Period			-	kWh
78	~~Prior Period kWh DG losses~~	~~Previous Filing, Schedule 3, Line [illegible], Column C~~			~~kWh~~
79	~~Cumulative Recoverable kWh savings~~	~~(Previous Filing, Schedule 3, Line [illegible], Column C Line [illegible])~~			~~kWh~~
[illegible]	Total Recoverable DG Savings	Line 77		-	kWh
[illegible]	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 21, Column C	$	#DIV/0!	$/kWh
[illegible]	Large General Service - Lost Fixed Cost Revenue Relating to DG	(Line [illegible] * Line [illegible])	$	#DIV/0!	
	Interruptible Power Service - Delivery Revenue - Demand				
	Energy Efficiency Savings				
[illegible]	Current Period			-	kW
[illegible]	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 83, Column C		-	kW
[illegible]	Cumulative Recoverable kW savings	~~(Previous Filing, Schedule 3, Line [illegible], Column C~~ Line [illegible] + Line 82)		-	kW
[illegible]	Total Recoverable EE Savings	Line [illegible]		-	kW
[illegible]	Interruptible - Lost Fixed Cost Rate	Schedule 4, Line [illegible], Column C	$	#DIV/0!	$/kW
[illegible]	Interruptible - Lost Fixed Cost Revenue Relating to EE	(Line [illegible] * Line [illegible])	$	#DIV/0!	
	Distributed Generation				
	Current Period				kW
[illegible]	~~[illegible]~~	~~[illegible]~~			~~kW~~
[illegible]	~~Cumulative Recoverable kW savings~~	~~[illegible]~~			~~kW~~
[illegible]	Total Recoverable DG Savings	Line [illegible]		-	kW
[illegible]	Interruptible - Lost Fixed Cost Rate	Schedule 4, Line [illegible], Column C	$	#DIV/0!	$/kW
[illegible]	Interruptible - Lost Fixed Cost Revenue Relating to DG	(Line [illegible] * Line [illegible])	$	#DIV/0!	

UNS Electric, Inc.
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units	(E) [illegible]
	Interruptible Power Service - Delivery Revenue					
	Energy Efficiency Savings					
[illegible]	Current Period			-	kWh	
	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line [illegible], Column C		-	kWh	
[illegible]	Cumulative Recoverable kWh savings	([illegible] Line [illegible])		-	kWh	
	Total Recoverable EE Savings	Line [illegible]		-	kWh	
[illegible]	Interruptible - Lost Fixed Cost Rate	Schedule 4, Line [illegible], Column C	$	#DIV/0!	$/kWh	
[illegible]	Interruptible - Lost Fixed Cost Revenue Relating to EE	(Line [illegible] * Line [illegible])	$	#DIV/0!		
	Distributed Generation					
97	Current Period			-	kWh	
[illegible]	~~Prior Period kWh DG losses~~	~~Previous Filing, Schedule 3, Line [illegible], Column C~~			~~kWh~~	
[illegible]	~~Cumulative Recoverable kWh savings~~	~~(Previous Filing, Schedule 3, Line [illegible], Column C + Line 73)~~			~~kWh~~	
[illegible]	Total Recoverable DG Savings	Line 97		-	kWh	
[illegible]	Interruptible - Lost Fixed Cost Rate	Schedule 4, Line 27, Column C	$	#DIV/0!	$/kWh	
100	Interruptible - Lost Fixed Cost Revenue Relating to DG	(Line 98 * Line 99)	$	#DIV/0!		
	Large Power Service - Delivery Revenue - Demand					
	Energy Efficiency Savings					
101	Current Period				kW	
102	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 103, Column C		-	kW	
103	Cumulative Recoverable kW savings	~~(Previous Filing, Schedule 3, Line 31, Column C +~~ Line 101 + Line 102)		-	kW	
104	Total Recoverable EE Savings	Line 103		-	kW	
105	Large Power Service - Lost Fixed Cost Rate	Schedule 4, Line 35, Column C	$	#DIV/0!	$/kW	
106	Large Power Service - Lost Fixed Cost Revenue Relating to EE	(Line 104 * Line 105)	$	#DIV/0!		
	Distributed Generation					
107	Current Period			-	kW	
[illegible]	~~[illegible]~~	~~[illegible]~~			[illegible]	
[illegible]	[illegible]	[illegible]		-	[illegible]	
[illegible]	Total Recoverable DG Savings	Line [illegible]		-	kW	
[illegible]	Large Power Service - Lost Fixed Cost Rate	Schedule 4, Line [illegible], Column C	$	#DIV/0!	$/kW	
[illegible]	Large Power Service - Lost Fixed Cost Revenue Relating to DG	(Line [illegible] * Line [illegible])	$	#DIV/0!		
	Large Power Service - Delivery Revenue					
	Energy Efficiency Savings					
111	Current Period			-	kWh	
112	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 113, Column C		-	kWh	
113	Cumulative Recoverable kWh savings	~~(Previous Filing, Schedule 3, Line 95, Column C +~~ Line 111 + Line 112)		-	kWh	
114	Total Recoverable EE Savings	Line 113		-	kWh	
115	Large Power Service - Lost Fixed Cost Rate	Schedule 4, Line 33, Column C	$	#DIV/0!	$/kWh	
116	Large Power Service - Lost Fixed Cost Revenue Relating to EE	(Line 114 * Line 115)	$	#DIV/0!		
	Distributed Generation					
117	Current Period			-	kWh	
118	~~Prior Period kWh DG losses~~	~~Previous Filing, Schedule 3, Line 99, Column C~~			~~kWh~~	
119	~~Cumulative Recoverable kWh savings~~	~~(Previous Filing, Schedule 3, Line 95, Column C + Line 97)~~			~~kWh~~	
[illegible]	Total Recoverable DG Savings	Line 117		-	kWh	
[illegible]	Large Power Service - Lost Fixed Cost Rate	Schedule 4, Line 33, Column C	$	#DIV/0!	$/kWh	
120	Large Power Service - Lost Fixed Cost Revenue Relating to DG	(Line 118 * Line 119)	$	#DIV/0!		[illegible]
[illegible]	Total Lost Fixed Cost Revenue Related to Energy Efficiency	Sum Line [illegible] + 16 + 26 + 35 + 46 + 56 + 66 + 76 + [illegible] + 96 + 106 + 116	$	#DIV/0!		[illegible]
[illegible]	Total Lost Fixed Cost Revenue Related to Distributed Generation	Sum Line [illegible] + 110 + 120	$	#DIV/0!		[illegible]
[illegible]	Total Lost Fixed Cost Revenue	(Line [illegible] + Line [illegible])	$	#DIV/0!		

UNS Electric, Inc.
Lost Fixed Cost Recovery Mechanism
Schedule 4: LFCR Test Year Rate Calculation

Line No.	(A) LFCR Fixed Cost Calculation		(B) Reference		(C) Totals
	Residential Customers				
1		Delivery Revenue	Schedule 5, Line 7, Column E	$	-
2		kWh Billed	Schedule 5, Line 7, Column B		-
3		Lost Fixed Cost Rate	(Line 1 / Line 2)	$	#DIV/0!
	Residential Customers				
4		Delivery Revenue - Demand	Schedule 5, Line 29, Column E	$	-
5		kW Billed	Schedule 5, Line 29, Column B		-
6		Lost Fixed Cost Rate	(Line 4 / Line 5)	$	#DIV/0!
	Small General Service				
7		Delivery Revenue	Schedule 5, Line 12, Column E	$	-
8		kWh Billed	Schedule 5, Line 12, Column B		-
9		Lost Fixed Cost Rate	(Line 7 / Line 8)	$	#DIV/0!
	Small General Service				
10		[illegible]	[illegible]	$	
11		[illegible]	[illegible]		
12		[illegible]	[illegible]		#DIV/0!
	Medium General Service				
13		Delivery Revenue	Schedule 5, Line 16, Column E	$	-
14		kWh Billed	Schedule 5, Line 16, Column B		-
15		Lost Fixed Cost Rate	(Line 13 / Line 14)	$	#DIV/0!
	Medium General Service				
16		Delivery Revenue - Demand	Schedule 5, Line 36, Column E	$	-
17		kW Billed	Schedule 5, Line 36, Column B		-
18		Lost Fixed Cost Rate	(Line 16 / Line 17)	$	#DIV/0!
	Large General Service				
19		Delivery Revenue	Schedule 5, Line 20, Column E	$	-
20		kWh Billed	Schedule 5, Line 20, Column B		-
21		Lost Fixed Cost Rate	(Line 19 / Line 20)	$	#DIV/0!
	Large General Service				
22		Delivery Revenue - Demand	Schedule 5, Line 40, Column E	$	-
23		kW Billed	Schedule 5, Line 40, Column B		-
24		Lost Fixed Cost Rate	(Line 22 / Line 23)	$	#DIV/0!
	Interruptible Power Service				
25		Delivery Revenue	Schedule 5, Line 22, Column E	$	-
26		kWh Billed	Schedule 5, Line 22, Column B		-
27		Lost Fixed Cost Rate	(Line 25 / Line 26)	$	#DIV/0!
	Interruptible Power Service				
28		Delivery Revenue - Demand	Schedule 5, Line 42, Column E	$	-
29		kW Billed	Schedule 5, Line [illegible], Column B		-
30		Lost Fixed Cost Rate	(Line 28 / Line 29)	$	#DIV/0!
	Large Power Service				
31		Delivery Revenue	Schedule 5, Line 25, Column E	$	-
32		kWh Billed	Schedule 5, Line 25, Column B		-
33		Lost Fixed Cost Rate	(Line 31 / Line 32)	$	#DIV/0!
	Large Power Service				
34		Delivery Revenue - Demand	Schedule 5, Line 45, Column E	$	-
35		kW Billed	Schedule 5, Line 45, Column B		-
36		Lost Fixed Cost Rate	(Line 34 / Line 35)	$	#DIV/0!

UNS Electric, Inc.
Lost Fixed Cost Recovery Mechanism
Schedule 5: Delivery Revenue Calculation

	(A)	(B)	(C)	(D)	[illegible]	[illegible] B x D
Line No.	Rate Schedule	Adjusted Test Year Billing Determinants	Units	Delivery Charge	[illegible]	Total Delivery Revenue
	kWh related					
1	**Residential Service (RES-01)**		kWh	$	100%	$ -
2	**Residential Service (RES-01 TOU)**		kWh	$	100%	$ -
3	Residential Service (RES-01 TOU SuperPeak)		kWh	$		$ -
4	**Residential Service (R-01 CARES)**		kWh	$	100%	$ -
5	Residential Service (RES-01 Demand)		kWh	$		$ -
6	Residential Service (RES-01 Demand TOU)		kWh	$		$ -
7	**Subtotal - kWh**	-	kWh			$ -
8	**Small General Service (SGS-10)**		kWh	$	100%	$ -
9	**Small General Service (SGS-10 TOU)**		kWh	$	100%	$ -
~~10~~	~~Small General Service (SGS-10 TOU-S)~~		kWh	$	100%	$
10	Small General Service (SGS-10 Demand)		kWh	$		$ -
11	Small General Service (SGS-10 Demand TOU)		kWh	$		$ -
12	**Subtotal - kWh**	-	kWh			$ -
13	Medium General Service (MGS)		kWh	$		$ -
14	Medium General Service (MGS-TOU)		kWh	$		$ -
15	Medium General Service (MGS-TOU-S)		kWh	$		$ -
16	Subtotal - kWh	-	kWh			$ -
17	**Large General Service (LGS)**		kWh	$	100%	$ -
18	**Large General Service (LGS-TOU)**		kWh	$	100%	$ -
19	**Large General Service (LGS-TOU-S)**		kWh	$	100%	$ -
20	**Subtotal - kWh**	-	kWh			$ -
21	**Interruptible Power Service (IPS)**		kWh	$	100%	$ -
22	**Subtotal - kWh**	-	kWh			$ -
23	**Large Power Service (LPS)**		kWh	$	100%	$ -
24	**Large Power Service (LPS-TOU)**		kWh	$	[illegible]	$ -
25	**Subtotal - kWh**	-	kWh			$ -
[illegible]	**Total kWh**	-	kWh			$ -
	kW related					
27	Residential Service (RES-01 Demand)		kW	$		$
28	Residential Service (RES-01 Demand TOU)		kW	$		$ -
29	Subtotal - kW	-	kW			$ -
30	Small General Service (SGS-10 Demand)		kW	$		$ -
31	Small General Service (SGS-10 Demand TOU)		kW	$		$ -
32	Subtotal - kW	-	kW			$ -
33	Medium General Service (MGS)		kW	$		$ -
34	Medium General Service (MGS-TOU)		kW	$		$ -
35	Medium General Service (MGS-TOU-S)		kW	$		$ -
36	Subtotal - kW	-	kW			$ -
37	**Large General Service (LGS)**		kW	$	50%	$ -
38	**Large General Service (LGS-TOU)**		kW	$	50%	$ -
39	**Large General Service (LGS-TOU-S)**		kW	$	50%	$ -
40	**Subtotal - kW**	-	kW			$ -
41	**Interruptible Power Service (IPS)**		kW	$	50%	$ -
42	**Subtotal - kW**	-	kW			$ -
43	**Large Power Service (LPS)**		kW	$	50%	$ -
44	**Large Power Service (LPS-TOU)**		kW	$	50%	$ -
[illegible]	**Subtotal - kW**	-	kW			$ -
[illegible]	**Total kW**	-	kW			$ -

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE – INTERIM CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
VACANT

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

Rebuttal Testimony of

Craig A. Jones

on Behalf of

UNS Electric, Inc.

January 19, 2016

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Exhibits:

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CAJ-R-2 Bill Impacts

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CAJ-R-5 Schedule H-4-FC

CAJ-R-6 TCA POA (clean and redline versions)

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Craig A. Jones and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of UNS Electric, Inc. ("Company").

Q. In general, what is the Company's concern with certain positions being expressed by many of the parties in this case?

A. Staff and the Company are the only parties in this case that have an interest that goes beyond a specific customer class, a small group of customers or a narrow special interest. The Company's filed case was an attempt to move to a more equitable rate design that recovers revenues in a manner that minimizes or eliminates intra- or inter-class subsidies where possible. In my rebuttal I will be addressing why certain proposals by many of the parties in this case specifically create either larger or additional subsidies for their specific special interest.

Q. What are the primary reasons for updating UNS Electric's rate design?

A. In this proceeding, the Company is attempting to modify its rates to (i) reduce intra-class subsidization where possible, (ii) promote fairness between like situated customers and recover costs from cost causers, (iii) provide rates designed to promote flexibility which will accommodate changing customer usage patterns while still recovering costs, (iv) promote rate structures that encourage the optimal integration of new energy technologies on the electric system, and (v) ensure that the Company continues delivering safe, reliable and affordable electric services for the benefit of all of our customers.

Q. Which Commission Staff and/or Intervenor testimony do you address in your Rebuttal Testimony?

A. I will be addressing the rate design testimony of most witnesses, including Residential Utility Consumers Office ("RUCO"), Arizonans for Electric Choice & Competition ("AECC"), NUCOR, Arizona Community Action Association ("ACAA"), Southwest Energy Efficiency Project ("SWEEP"), Fresh Produce Association of Arizona ("FPAA"), Walmart, the Vote Solar Initiative ("Vote Solar"), The Alliance for Solar Choice ("TASC"), Western Resource Advocates ("WRA") and Arizona Utility Ratepayer Alliance ("AURA"). I will not have any Rebuttal Testimony for AIC or APS other than to say I support most of their positions.

II. <u>REBUTTAL OF STAFF WITNESSES</u>

Q. Would you summarize the Company's positions as it relates to ACC Staff witness, Mr. Solganick's Direct Testimony in this proceeding?

A. Yes. Mr. Solganick provides a summary of his testimony starting on page 2. In that summary he states that; "Rates should be based on costs and recognize the concepts of customer, demand and energy, including time-of-use ("TOU")." The Company agrees with this general concept.

Staff's revenue allocation proposal does not meet the goals the Company intended in its filing, but in the interest of gradualism and movement in the right direction, the Company is willing to adjust the allocation of revenue between the rate classes using Staff's suggestion as a guide.

The Company supports Staff's recommendation to move all residential and small general service ("SGS") customers to a three-part TOU based rate design. However, the Company believes that certain modifications to Staff's rate design proposal are appropriate and I discuss those modifications in my testimony. The Company is also willing to leave the rate design portion of this proceeding open for a specified period of time in order to make any necessary revenue neutral adjustments to rates to address any significant, unintended consequences that may affect our customers or the Company. Additionally, as explained by David Hutchens and Dallas Dukes in their Rebuttal Testimony, the Company believes that customer engagement and education is an important part of implementing any changes to rate design. Staff's suggestion for the CARES customers is reasonable. The Company strongly supports having CARES customers on the same rate as the standard residential rate, with a discount available to qualifying customers in place of having a special rate for the CARES customers. The specific discount will need to be calculated once final rates are calculated. The Company agrees the total amount of the CARES discount should not be reduced, but believes that any increase in the total amount of the discount should be recovered by adjusting the final rates for other customer classes to capture the added discount, or through a process that allows for timely recovery of the additional discounts.

The Company supports eliminating the current Interruptible Power Service ("IPS") rate in the Company's next rate case, assuming the proposed interruptible Rider R-12 is approved.

The Company disagrees with Staff's position that any changes to the existing net metering tariff or waivers of the net metering rules should not be made at this time. UNS Electric witness Carmine Tilghman, addresses this in his rebuttal testimony.

The Company can accept Staff's recommendation relating to the meter upgrade opt-out and agrees they should be moved to the 3-part rate in the same manner as all other customers, simply without a transmitting meter and at a higher cost for the meter reading and billing.

The Company does not support the Buy-Through offering and opposes any variation that results in costs being shifted to either the Company or the other customers. Consistent with Staff's recommendation, the Company believes any such cost shifts be addressed before the Buy-Through offering is considered.

The Company has not proposed pre-approval of lost non-fuel revenue in its Economic Development Rider ("EDR").

The Company accepts Staff's recommendation to remove the fixed charge option relating to the Lost Fixed Cost Recovery ("LFCR") mechanism; however, we believe Staff's position on the rest of the requested changes guarantees the Company will not be able to recover lost non-fuel revenues associated with complying with the Commission's Energy Efficiency ("EE") and REST rules. Although Staff's proposed three-part rate helps reduce revenues lost due to DG, it certainly does not eliminate it. It is the Company's hope that rate design will evolve over time so that the DG component of the LFCR can be eliminated. However, requiring that the DG component of the LFCR be terminated in UNS Electric's next rate case, without an offsetting requirement that rate design changes will provide an opportunity to recover the lost revenues would be much too soon.

Q. Please provide your response to any specific concerns you have with Mr. Solganick's Direct Testimony.

A. On Page 13, line 1-3, Mr. Solganick mentions that as three part-TOU rates become fully implemented, the magnitude of the LFCR will diminish and can be eliminated for DG. I agree with the statement that properly designed three-part rates will move us in that direction. However, a portion of the fixed costs is still being recovered through volumetric rates, therefore the LFCR still has an important purpose.

Q. Does the demand charge, in combination with the increased basic service charge, allow the Company to recover all of its fixed costs?

A. No. The Company agrees both the Company's and Staff's rate design proposals are a good start in addressing appropriate fixed cost recovery, but the proposals still leave a significant percentage of the Company's fixed costs subject to recovery though volumetric rates. And, especially for DG customers, that will mean a continued under-recovery of the fixed costs required to serve the customer. The Company would still need to recover its lost fixed costs through the LFCR until a future rate design change mitigates those lost revenues in order to provide the Company with a reasonable opportunity to earn its allowed return.

Q. Will you explain what fixed costs you believe will remain under-recovered?

A. Yes. While on Page 45, lines 20-23 of Mr. Solganick's Direct Testimony, Staff has reserved the opportunity to change its position in Sur-rebuttal Testimony, it has recommended no changes be made to the net-metering rules (including the allowance of banking), even for new net-metering customers. If the current net-metering provisions are not, a substantial portion of a DG customer's volumetric consumption will continue to be offset by the combination of instantaneous generation offsets and carried forward banking offsets. Many DG customers offset as much as 100% of their energy volumes.

Based on the bill frequency data developed by the Company over 57% of the DG customers' electric bills are for zero kWh. Under the phased in three-part rates proposed by Staff approximately 27% of the Company's fixed costs will remain in the volumetric energy rate. Therefore, this same percentage of fixed costs will remain unrecovered if a DG customer's system is sized to meet 100% of their annual energy needs. On average, this would equate to approximately $160 per year of unrecovered fixed costs for a typical customer on an annual basis. This amount should still be included in the LFCR as lost fixed costs until rate design can be further modified in future rate proceedings.

Q. Mr. Solganick, on Page 14, line 6, has recommended keeping the rate design portion of the rate case open for some specified period of time to allow for tracking of issues and revenues associated with transitioning to three-part rates. Is this a concern for the Company?

A. While the Company normally prefers closure to all rate case related issues sooner rather than later, the implementation of three-part rates for all customers is a special circumstance which may yield results that were unintended. UNS Electric could support keeping the rate design portion of this rate case open for a period of time in the event that significant unintended consequences arise that adversely affect the Company or its residential or SGS customers. For example, the estimation of monthly billing demands will be difficult because of the potential for customer response and the limited data base used to develop that billing determinant. Mr. Dukes describes the Company's outline of the transitional plan being proposed by the Company to establish the particular steps and processes that will need to be executed during the entire transitional period to make this transition to three-part rates as seamless and issue free as possible.

Q. If the Company agrees with keeping the rate design portion of this case open for a limited period of time, what guidelines would the Company want to be included?

A. The Company believes the following constraints or guidelines should be included:

1) The final transition plan should define how long the rate design remains open, and define the types of adjustments that might be needed to address any potential significant unintended consequences or "extreme" impacts of any "vulnerable customers" (as discussed by Staff). All efforts will be made to minimize or avoid "extreme" impacts or the creation of "vulnerable customers", but the possibility should be considered and any resulting changes be kept to a minimum.
2) The intent of any rate design modification should be limited to mitigating these unintended consequences or "extreme" impacts if they are created and should be open to adjustment of billing determinants and or rates in the specified rate classes if it is determined that the information obtained from the original data used to support the initial three-part rates is either under or over stated. These changes should be addressed if the expected revenues (using all available actual data, adjusted for normal weather) is more (or less) than when the initial rates were created. Any changes should be limited to the residential and SGS rate classes, but may be applied to the other customer classes if needed.
3) Any adjustment to the initial rates should be designed to be revenue neutral to the Company (increased or decreased) with the intended recovery level for the class. This could include adjusting the demand charge up or down based on actual kW data generated during the transition period, with appropriate adjustments to the volumetric rates to maintain a neutral impact. Since the three part rate is a TOU rate and will be expanded to all residential and SGS customers, some modification may need to be made to recover peak versus off-peak fuel costs, on a revenue neutral basis. Other options that could be considered would be the creation of a special group of

"vulnerable customers", if necessary, to be in effect until the next rate case, when they would move to the standard rate and any temporary rate class would be eliminated.

Q. On Page 24, lines 3-7, Mr. Solganick recommends revenues be allocated in a specific manner. Does the Company agree with his recommendations?

A. In general, the Company understands Mr. Solganick's recommendation, which included more cost being allocated to the larger rate classes and less to the residential rate class. The Company can appreciate why the recommendation was made and will adjust its allocation to reflect something closer to what Staff recommends than what was originally proposed by the Company. The Company still believes additional costs should be shifted from certain large classes to the residential and SGS rate classes based on the results of the Company's Class Cost of Service Study ("CCOSS") which indicates the large classes are currently subsidizing the residential and SGS rate classes. The Company does understand Staff's concerns that new rates should be designed to reflect appropriate cost allocation while still setting rates that exhibit the principle of gradualism. While there may be a number of ways to get there, they all involve allocating more cost to the residential and SGS classes and less to the larger rate classes.

The Company recalculated the total revenues to reflect the adjusted total revenue requirement recommended by Staff and as shown in Mr. David Lewis' Rebuttal Testimony to reflect an approximate $18.5 million increase in test year revenues. The Company then reallocated the revenue requirement along the lines suggested by Staff. **Exhibit CAJ-R-1** reflects that proposed reallocation of revenue recovery to each of the rate classes including an adjustment to fuel costs as suggested by Staff witness Barbara Keene.

Once the revenue amounts are allocated to each class, a revised revenue proof was developed that uses the same adjusted test year billing determinants used in the Company's Direct Testimony, while maintaining the current rate design. Staff's recommended basic service charges are reflected in the revenue calculations and any remaining revenue requirement for the specific rate class is applied to an increase to the volumetric charges and/or demand charges as appropriate in existing rates. All of these changes were made with consideration to typical customer bill impacts being kept within an acceptable range, knowing that there will always be a few outliers. Billing determinants for on- and off-peak volumes were used to determine on- and off-peak fuel recoveries. A summary of the resulting bill impacts are reflected in **Exhibit CAJ-R-2**.

Q. Do you have concerns with Mr. Solganick's proposed basic service charges and other pre-transition rates as discussed in his Direct Testimony starting at Page 27?

A. The Company believes that modernizing rate design in a manner that allows for more appropriate recovery of fixed costs is an essential component of this rate case and that its proposed residential basic service charge of $20 per month more appropriately implements this goal. However, the Company is willing to accept Staff's recommended basic service charge of $15 per month in conjunction with the three-part rate as a step in the right direction and has used Staff's proposed basic service charge amounts for all classes in its revised revenue proof.

Further, while the Company is still of the opinion that inverted block rates do not reflect appropriate cost recovery; for purposes of the transition rates only, the Company is willing to accept the retention of the existing residential and SGS rate design for the interim period prior to implementing the three-part rates. If for any reason the three-part rate is not approved by the Commission for all residential and SGS customers, the

Company believes its originally proposed basic service charge and the elimination of the third rate tier for the residential class is the superior rate design.

Q. Did you include bill impact calculations of both the transition rates[1] and the proposed three-part rates once they are applied to the customers?

A. Yes. In addition to the summary of bill impacts provided in **Exhibit CAJ-R-2**, I am attaching a version of the H Schedules as **Exhibit CAJ-R-4**, which provide bill impacts for both the transitional rates being proposed herein, and the impact of the new three-part rate based on a sample of customers with demand data when they migrate from the transitional rates to the 3 part rates. This information can be found in Schedule H-4 of my **Exhibit CAJ-R-4**. The bill impacts of the transitional rates are based on unadjusted test year billing determinants. Since we do not have actual demand data for all residential and SGS customers, the impact of the three-part rate is based on data we have from a load research sample group, which is based on the actual usage data of a sample group of customers.

Q. In the Company's direct case, it was proposed that an approximate $9.5 million credit resulting from the Gila River plant be credited to the customers during the first 12-months these new rates were in effect. Did you provide bill impacts reflecting the impact of this credit?

A. Yes. I have attached as **Exhibit CAJ-R-5** a version of the H-4 schedules that duplicate those I provided in **Exhibit CAJ-R-4**, however, this version reflects the $9.5 million credit being returned over a twelve month period as proposed in the Company's Direct Testimony. These calculations can be found in Schedule H-4-FC of my **Exhibit CAJ-R-5**. The results are also summarized on my **Exhibit CAJ-R-2**.

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[1] Transitional rates are defined as the interim two-part rates (reflecting the revenue requirement approved in this case) that will be in effect until residential and SGS customers are transitioned to three-part rates.

Q. Has the Company provided similar information for the SGS rate class using Staff's recommendations?

A. Yes. Staff's recommended basic service charge and the remaining rates as discussed herein are included in both the residential and SGS portions of revised Schedule H included in both **Exhibit CAJ-R-4** and **Exhibit CAJ-R-5**. The specific rates are reflected in Schedule H-3 and the bill impacts are reflected in Schedule H-4. These exhibits include rates and bill impacts for the other classes as well.

Q. Is the Company proposing to add language to the SGS tariff to address the concern expressed by Mr. Solganick at Page 30, lines 6-9 relating to the movement of an SGS customer from the SGS rate class to the medium general service ("MGS") rate class when the customer uses more than 12,000 kWh in two consecutive months?

A. Yes. That provision will be clearly stated in the final SGS tariff filed in compliance with the final order in this proceeding. The provision currently exists in the SGS tariff so this is not a new concept and therefore the Company did not perform any additional studies or analysis. Prior to the last rate case, customers using more than 7,500 kWh in two consecutive months were automatically moved to the next larger class. This was changed to 12,000 kWh or more in the last rate case. Therefore, it is not expected that customers will be impacted by this provision.

The 12,000 kWh threshold is based on the 20 kW minimum demand for the MGS customer class. A customer would need a load factor greater than 80% to consume 12,000 kWh and not reach a 20 kW demand. Because very few customers in the SGS class would maintain an 80% or greater load factor based on the evaluation of like customers in our load research data and most SGS customers did not have meters to measure demand, the Company felt this was a good way to estimate a customer's demand. This allows a reasonable way for the Company to identify customers with usage levels and demand levels that are more appropriate for the larger rate class and move them into that class.

Q. Since most of the Company's non-fuel costs are fixed, would the Company like to see a higher demand charge for these three-part rates than Mr. Solganick has proposed for the residential and SGS rate classes?

A. Yes. On Page 31, lines 5-10, Mr. Solganick recommends using 75 percent of the unit cost for distribution as the guide for creating the demand charge applicable to the residential and SGS rate classes. This leaves a portion of the distribution related costs, all of the transmission related costs and all of the generation related costs to be recovered in volumetric rates. These are all fixed costs being incurred by the Company to provide service to the customer. The Company believes most, if not all, of these costs should also be reflected in any proposed demand charge.

Q. Is the Company willing to accept Staff's proposal for purposes of implementing a "first-step" demand based rate for customer classes that have not traditionally been accustomed to three-part rates?

A. Yes, with a couple of modifications. For purposes of transitioning into the three-part rate, the Company is willing to agree with this limited level of cost recovery in the demand charge. The Company is willing to agree to this, but believes the reduced demand charge provides justification for maintaining the LFCR mechanism in place until a substantial decrease in the volumetrically recovered costs can be addressed in a future rate case. The other key change the Company is proposing would not change Staff's proposed dollar level of demand charge, but does change the specific costs being recovered through that charge. If the demand charge is based on the customer's on-peak demand, then it should recover the related generation costs. Distribution costs should be associated with the non-coincident peak a customer generates, which would be more appropriately recovered using the customer's individual peak, regardless of when that peak occurs. Since the generation costs are higher than the distribution costs, the initial charge may need to be based on a lower percentage of the total generation unit costs calculated in the CCOSS (say 50%), but that level would be based on calculating a final demand charge that approximates the one proposed by Staff, something close to $5.00 per kW for residential customers in this rate case.

Q. What other modification would the Company propose to Staff's version of the three-part rate?

A. As three-part rates were evaluated, some concerns were brought up relating to what we described as "outlier bills." These bills reflect months where usage habits could cause the bill to be higher when changing from a two-part rate to a three-part rate. The Company is proposing to add a transitional or temporary mitigation adjustment to the calculation of the demand component of the rate. This mitigation adjustment would be built into the billing process and would review each customer's billing determinants before the bill is issued. If the customer's site load and measured kW for the billing period result in a load factor of less than 15%, an algorithm in the billing system will use a billing demand that is lower than the measured demand. The billing demand would be calculated by assuming the site load was utilized at a 15% load factor. This reduces the demand related charges for all customers who have a load factor of less than 15%. Based on the review of our load research group of customers, this moderates the bill impact for nearly all customers. When comparing bills under the two-part rate and a three-part rate on a revenue neutral basis, residential customers generally see bill increases of no more than 3.2%, with over 90% of the customers seeing less than a 13.6% increase. Overall, slightly more than 25% of the customers would see a bill decrease when moving to a three-part rate on a revenue neutral basis.

Q. Would you provide an example of how this mitigation adjustment will work?

A. Yes. First, the definition of Load Factor (LF) is average load divided by maximum load and in formula form for the billing period it is:

LF = site load for billing period in kWh / (billing days * 24 hours/day * kW (measured))

The mitigation adjustment uses this calculation to test for the following:

If LF $\geq$ 15%, no adjustment to the bill calculation,
If LF < 15%, billed kW adjusted to match a LF of 15%

Let's compare the billed demand under two scenarios: 1) total site load of 1,000 kWh in one month with 8 kW of load and 2) total site load of 1,000 kWh in another month, but the customer used a welder one day and produced 14 kW of load, the same kWh usage, but nearly double the system capacity or KW. The system would test month number 1:

LF = 1000 kWh / (30 days * 24 hours/day * 8 kW), or a LF of 17.36%

The first bill would use the measured demand amount of 8 kW and calculate the bill. This is the way nearly 85% of the bills will be calculated. The load factor for the second scenario would be:

LF = 1000 kWh / (30 days * 24 hours/day * 14 kW), or a LF of 9.92%

In this case the system will recognize the LF is below 15% and revert to the algorithm to determine the "billed" demand for this customer in this one month. This time the calculation is done in reverse:

> LF (assumed to be 15%) = 1000 kWh / (30 days * 24 hours/day * x kW), solving for x, gives you a "billed" kW of 9.26 kW

Since the customer's measured demand was 14 kW, but the load factor was less than 15%, the billed demand was adjusted to 9.26 kW. Assuming a $5 per kW demand charge, the customer's bill was reduced by approximately $24. Larger load factor customers save with three-part rates so no adjustment was proposed for the larger customers. The test level of a 15% LF was determined by calculating bills for all customers in the load research group and identifying the level that provided a fair level of protection from large dollar bill impacts.

Q. **Does the Company wish to leave this mitigation adjustment in place permanently?**

A. No. This proposal was designed to complement the other provisions being proposed with the implementation of three-part rates to mitigate some of the significant bill impacts that may occur, thus allowing the customers to acclimate to the new rate design and adjust their individual usage habits or add new technologies that will allow them to lower their energy costs. It is the Company's position that this mitigation adjustment would be phased out as soon as possible, but no later than the implementation date of the next rate case.

Q. Mr. Solganick has requested the Company provide additional information relating to the proposed basic service charge split for the MGS and LGS rate classes. Will you explain the difference?

A. Yes. In response to Mr. Solganick's request at Page 33, line 20 of his Direct Testimony the Company reviewed its meter cost data. In total, the LGS class will contain only 17 customers. About 40% of that class is moving from the former Large Power Service ("LPS") class. The LPS class required power factor equipment to be in place. Therefore many in the class have higher cost customer related equipment. Additionally, as mentioned in his testimony, the unit cost calculated in the CCOSS for the MGS and LGS rate classes combined is approximately $265 per month. Since approximately 40% of the LGS customers are moving from a rate class that reflected a $1,200 monthly basic service charge and 60% were the largest customers in a class with a $50 basic service charge, the Company felt a $300 per month basic service charge is a more gradual change in the rate. The MGS customers were formerly paying a $50 basic service charge therefore a move to a $100 per month basic service charge seemed reasonable. The Company believes its proposed basic service charges are reasonable and requests that they be approved.

Q. On Page 34, line 8, Mr. Solganick also requests that the Company provide additional support for creating a 750 kW maximum demand amount for an MGS customer to remain on the MGS rate and the proposal that the customer be moved to LGS the month after they attain the 750 kW level. Will you provide additional explanation for the Company's proposed maximum demand amount for this rate class?

A. Yes. The Company did an extensive evaluation of how the various minimum and maximum demand amounts would impact customer bills. The main purpose of creating the additional MGS rate class was to establish classes of service that contained a more homogeneous grouping of customers based on similar usage habits. By establishing minimum and maximum demand amounts for the various classes, this goal is met. While an individual customer's load factor and usage habits will determine what the bill impact will be, the Company reviewed impacts for all migrating customers and settled on a range that did the best job of mitigating those impacts.

In order to respond to Staff's concern the Company queried all anticipated MGS customers with a demand in excess of 400 kW during the test year but did not otherwise reach the 750 kW level (had they reached 750 kW they were already assumed to be included in the LGS rate class). A total of thirty-one customers were identified. To determine the bill impact that would result if any of these customers reached the 750 kW level in a single month, and then returned to their normal (lower than 750 kW per month) test year usage, the first month of the 12-month calculation was reset at 750 kW to determine what the resulting bill would have been. The impact resulted in a bill, during the modeled year, increasing in a range from a 0.3% and 1.1% with no other rate changes. Therefore, it is the Company's opinion that, at most, thirty-one customers could be affected by this provision with a maximum bill impact of less than 1%. In reality, based on our current customers, the level the Company chooses will most likely result in no impact to the customers in this class unless they modify their usage habits substantially and at that point they should change rate classes anyway.

Q. At the bottom of Page 35 of Mr. Solganick's testimony, he requests additional support of the 450 kW minimum demand that the Company is proposing to be included in its LGS rate. Please provide additional information in support of this proposal.

A. Throughout this case, the Company has attempted to propose rate design and conditions relating to providing services to our customers that move toward treating like-situated customers in a similar manner. With that in mind, the Company began looking at the creation of the new service class. Most of the former LGS customers were moved to the MGS class, with a few of the largest former LGS customers and all of the non-69 kV former LPS customers moving into a single rate class, the new LGS class. To maintain a class designed for a homogeneous group of customers, conditions had to be placed on the rate class to maintain that homogeneity. We considered many different caps for the MGS class and floors for the LGS class with the goal of maintaining the homogeneity of the LGS rate class. The MGS cap of 750 kW and the LGS minimum billed demand of 450 kW met this goal. For those customers the Company anticipates moving into the new LGS rate class, their minimum demand was 486 kW. This is above the proposed minimum, thereby confirming that only customers who should be in this class are included and they will not be affected by the 450 kW floor. Also, all of the largest LGS customers that the Company projected would remain in the new LGS class had measured demand of greater than 750 kW during the test year. The ratchet will result in all anticipated LGS customers having a billed demand greater than 450 kW (75% of 750 kW = 563 kW). Therefore, the minimum demand will not impact any of the anticipated LGS customers unless their usage habits change. If that happens, they should move to the MGS class any way.

Q. **Staff requested justification for the rates being proposed for the School TOU rates on Page 37, line 6 of Mr. Solganick's Direct Testimony. Please explain the Company's reasoning for the proposed rates.**

A. After its prior rate case, the Company worked with Staff and school representatives to create a School TOU rate. It was part of the final order in the rate case and was not originally proposed in the Company's filing. The Company worked with Staff to create a rate that generally modeled the peak periods and design of a school rate that was in place for APS. This tariff was being designed outside of a rate case and the Company was concerned that the final rate be revenue neutral if possible. The peak period is not based on the Company's true peak period and is purely designed to accommodate the needs of a school schedule. As the rates were created after the last case, Staff suggested the rates be slightly higher since the on-peak period was shorter to protect the revenue neutral theory. There have been no customers placed on the tariff so the Company simply used the originally established guidelines to create the new tariff and increased the components proportionally to mirror the standard TOU rate proposed by the Company.

Q. Does the wattage charge being proposed by the Company in its lighting rate include the ballast load for purposes of determining which wattage the customer will pay?

A. No. The current wattage charge in the Company's lighting rate is limited to the wattage of the bulb installed. The Company's believes the lighting program today under recovers its fully loaded cost. The Company's intentions prior to the next case is to conduct a cost study of the current program and will have more information on LED lighting to reflect additional cost recovery in the lighting tariff.

Q. Does the Company agree with Staff's recommendation as it relates to the CARES customers?

A. Yes. In order to provide CARES customers with the same discount level they currently receive, the Company must provide discounts totaling approximately $1 million to support Staff's position.

In the test year, approximately $600,000 of CARES discounts were allocated other customer classes. This is the discount realized by an average of approximately 6,200 CARES customers during the test year. The additional discount these CARES customers are benefiting from is clouded in the numbers of the revenue proof. Since these CARES customers generate nearly 75,000 bills each year and every bill is discounted by the difference between the residential basic service charge of $10.00 per month and the

CARES customers current basic service charge of $4.90 per month, or a difference of $5.10 per bill, the total additional discount realized by these CARES customers is 75,000 times $5.10 or approximately $380,000 per year. When combined with the approximate $600,000 per year of direct percentage and flat rate discounts realized during the test year, this reaches nearly $1 million of benefits the current CARES customers receive. The method proposed by Staff will need to provide credits reaching nearly $1 million to keep the overall discount about the same as was realized under the rates originally proposed by the Company. This issue will be discussed further when I address the Direct Testimony submitted by ACAA witness Cynthia Zwick.

Staff's position is that CARES customers' bills should be calculated in the same manner as a standard residential customer. This would include each of the rate components, including the basic customer charge, demand charge, volumetric charges and riders. The discount approved by the Commission should be applied to that bill. The Company agrees with this position. UNS Electric supports offering a discount to the bills of low income customer qualifying for the program, but also sending accurate price signals. By moving to a consistent rate design, they receive the same pricing signal as a standard residential customer.

The Company proposes that the CARES discount be applied as a percentage reduction that limits the bill impact on CARES customers to an increase that is in the same general dollar amount as the standard residential customer. Although a single percentage amount would be preferred for all CARES customers, bill impacts may require a different percentage discount for each category of CARES customers (frozen CARES-Medical and Standard CARES customers). If that is the result of this proceeding, future rate cases should seek to move the different percentage discounts to a single discount amount for all CARES customers. And like the current CARES tariffs, once a specific kWh usage has been reached for the month, a fixed credit will be applied instead of the percentage credit. There is no cost basis for maintaining multiple levels of discounts for like situated customers just because some bills were heavily discounted. My **Exhibit CAJ-R-2** also shows the impacts of the transitional rates on the CARES customer using a typical monthly amount of kWh. The monthly dollar change for a typical customer was limited to an amount that was either near or below a standard residential customers monthly bill change.

Q. Please summarize what the Company is proposing for the CARES customers?

A. In summary, the CARES customers should be served under the standard rate they would otherwise qualify for, and if they meet the specified income qualifications, a standard percentage discount would be applied to their total bill before taxes. The Company proposed to keep the current income qualification level, which is 150% of the Federal Poverty level. The percentage discount would be calculated once final rates are decided in this proceeding and will be designed to provide the same benefit, on average, the current CARES customers receive. The total discount would equate to approximately $1 million, in total, for the entire CARES class (both frozen and open) and will be recovered by adding the $1 million to the revenue requirements of the other rate classes.

Q. Mr. Solganick requested the Company provide additional information to verify that the existing IPS customers are subsidized by the LGS customers?

A. First, on Page 52, line 7 of my filed Direct Testimony I do mention that the IPS customer class is subsidized, and I suppose I should have emphasized they are subsidized by all customers not just other LGS customers. To verify that the IPS customers are subsidized is a simple matter of calculating a bill using the existing IPS rate and the existing LGS rate with the same billing determinants. I have provided this calculation as **Exhibit CAJ-R-3**. Referring to this exhibit, you can see, the difference between what the IPS customer pays and what the same level of usage generates as an LGS customer is approximately $2,000 for this one month's bill. It is the Company's opinion that since no interruption has occurred during the test year or any recent years prior to the test year, the level of service these IPS customers are receiving is the same quality as the firm LGS customers. Therefore they are receiving the same level of service for $2,000 less in this example. That means the IPS savings are being shifted to all other rate payers in order to recover the overall revenue requirement authorized for the Company. This type of subsidy is what the Company is trying to either reduce or eliminate with the proposals being made in this proceeding.

Q. **Aside from this clarification do you have any additional concerns with Staff's recommendation as it relates to the Interruptible service rate?**

A. No. Staff accepted the Company's proposed new Interruptible Rider-12 and has not opposed our freezing the current IPS rate, thereby limiting it to the currently existing customers on this rate. Staff has also recommended the existing IPS tariff be eliminated in the Company's next rate case. The Company agrees to do this in the next rate case.

Q. **Do you accept Mr. Solganick's recommendations as it relates to the Service Fee Charges discussed on Pages 46 and 47 and the AMI Opt-out charge discussed on page 48 and 49 of his Direct Testimony?**

A. Yes. We will work with Staff to finalize the specific wording necessary to convey the recommendations made, including language to modify how we will charge for requests from the residential and SGS rate classes for interval data during the transition period while customers are trying to figure out how the new three-part rates will be affecting them.

Q. It does not appear that Staff agrees with many of the proposed changes the Company wishes to make to the LFCR mechanism. Would you like to address some of Staff's concerns?

A. Yes. It appears the only change proposed by the Company, relating to the LFCR, that Staff found acceptable is the elimination of the fixed charge option. No customers have participated in the fixed charge option to date and we wish to eliminate it. Staff appears to oppose the Company's other proposals to amend the LFCR. Additionally, for some reason Staff believes the LFCR related lost revenues associated with DG will go away with the first step of proposing its initial demand charge in a three-part rate, thereby justifying the elimination of DG related LFCR recoveries. The Company disagrees with this concept and believes the Staff should reconsider this position.

Q. Why do you believe Staff is wrong as it relates to the LFCR related changes requested by the Company?

A. The first item Staff disagrees with is the Company's proposal to blend the EE and DG percentages that are currently shown as separate entries on the customer's bill into a single adjustment. The primary reason the Company proposed this change is to eliminate confusion and simplify the bill the customer receives. The change does not impact the total amount charged to the customer and it would be one step in the direction of making the bill more customer friendly.

The second item opposed by Staff is the inclusion of fixed generation costs in the LFCR rates. Staff seems to believe the Company has some level of flexibility "to adjust its purchases to match its short-term needs" (Solganick; Page 55, line 4). The Company does not disagree that it can adjust its "purchased" generation if sales change. Adjusting costs associated with "purchased" generation will automatically be reflected in the PPFAC rates and any savings (or costs) will be passed on to the customers as a revised fuel cost.

The Company believes the PPFAC addresses these avoided (or additional) costs in a timely and accurate manner, but does not believe they have anything to do with the LFCR. Staff has provided no evidence or explanation as to how the Company's lost fixed costs are addressed by changes in the PPFAC, when PPFAC revenues are specifically excluded from the LFCR calculations.

Adjustments in "purchased" fuel (generation capacity or otherwise) have no impact on our ability to recover fixed costs that are included in non-fuel related base rates. When rates are created, the fixed cost associated with the Company owned generation facilities and related equipment is included in the costs 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 cost. Absent a rate case, there is no way to realign the recovery of those lost fixed costs if reduced by DG or EE. The Company does recognize that some level of those costs could be recovered if sales growth returns to a level that sufficiently offsets the revenues lost through DG and EE.

For UNSE, adjusted test year sales in the last rate case were approximately 1,741 GWh for the 12 months ending June 30, 2012. The adjusted test year sales in this case were approximately 1,601 GWh for the 12 months ending December 31, 2014, an approximate decrease of 8%. Even though this reduction is more than DG and EE related reductions, this very clearly shows that during the last 2 ½ years, sales have not increased sufficiently to offset DG or EE losses. The LFCR specifically identifies lost fixed costs associated directly with DG and EE sales reductions and the Company believes it should be allowed to recover those Commission-mandated losses which include fixed generation costs.

The LFCR was supported by all parties in recognition of the fact that recovery of fixed costs are reduced as the result of Commission mandates and that it was fair that a form of recovery be established to offset that. The Company believes generation costs should be included in this amount.

Q. Staff also opposes changing the LFCR provision that only allows recovery of 50% of the non-generation related portion of any demand charge. Why do you believe this provision inappropriately reduces the amount of lost fixed cost revenue the Company should be allowed to recover?

A. The Company believes that this is another arbitrary adjustment to reduce the amount of Commission-mandated lost fixed costs the Company is able to recover. Not only are fixed costs being recovered through the demand charge being reduced by the generation component included in the demand charge, the remaining components in the demand charge are further reduced by 50%.

A simple example may help explain why this is important. Assume a demand charge is $13 per kW. If the generation component is $3, then $10 is left. The current LFCR states the company is only allowed to recover 50% of that. This leaves the LFCR recovering $5 of the $13 demand charge. For every unit of demand the customer avoids due to DG or EE, the Company loses $13 of fixed cost recovery, but is only able to recover $5, or 38%.

As you can see, this leaves a very small portion of the fixed costs assigned to the demand rate to be recovered in the LFCR. Additionally, this arbitrary reduction only applies to verifiable reductions to demand amounts. Specifically, those demand units identified and verified as relating to either demand based EE programs or DG demand reductions coincident with the customers' billing peak. These parameters already create a quantification of lost demand revenues that is very narrowly defined and limited to specifically lost demand revenues resulting from DG and EE mandated activity. Why reduce the lost fixed cost recoveries associated with these vary narrowly defined demand losses by another 50%? In the Company's opinion this is an unfair reduction and should be eliminated.

The Company does recognize that some level of those costs could be recovered if the economy returns and the sales start to increase sufficiently to offset the kW revenues lost through DG and EE, but that has not happened to date. UNS Electric's adjusted test year kW sales in the last rate case were approximately 2.033 GW for the 12 months ending June 30, 2012. The adjusted test year kW sales in this case were approximately 1.880 GW for the 12 months ending December 31, 2014, an approximate decrease of 7.5%. Again, even though this is more than EE and DG related reductions, this very clearly shows that during the last 2 ½ years, sales have not increased sufficiently to offset DG or EE losses.

Based on known and measurable historical data there is no reason to reduce the level of lost fixed cost identified as being related to Commission mandated DG and EE related activity. Therefore the Company recommends that the Commission recognize these losses and add generation related losses and all demand related losses back into the LFCR rates for future recovery of lost fixed costs.

Q. **Mr. Solganick also mentions the possibility of double recovering certain lost fixed costs if generation is added back to the LFCR rate and the EDR is approved. Do you agree with this proposal?**

A. No. First, as mentioned above, the Company has experienced a loss in sales of over 140 GWh since the last test year. While the Company hopes this trend is not repeated between this rate case and the next, the economy has not made any substantial improvement in this service territory. The rates paid by any qualifying EDR customer would be at the reduced rates specified in the EDR and would be incremental only until the next rate case at those reduced rates. If there is a concern about double recovery of generation costs, the Company would not be opposed to excluding EDR related revenues from any LFCR calculation until the next rate case. The Company only desires to recover quantifiable lost fixed costs associated with Commission mandated DG and EE losses.

Q. Should the LFCR cap be increased from 1% to 2%?

A. Yes. If the Commission accepts the Company's other LFCR recommendations it should increase the cap. The cap may not be reached and if it is not, then the change will have no impact on customers. Even if the Commission does not accept all of the Company's proposals, changing the cap, based on historical LFCR filings, will not have an impact on the customers.

Q. Mr. Solganick also opposes the recovering any lost fixed costs generated by the "Buy-Through" rate in the LFCR. Is that a concern to the Company?

A. Yes, assuming the "Buy-Through" rate is approved in a form that creates lost fixed cost revenue. If the "Buy-Through" rate is denied by the Commission or if the design of the tariff is such that the participating customers pay their full retail rate then no lost fixed cost recoveries will be necessary and there will be no need for this provision to be added to the LFCR. Staff has indicated they have no specific objection to the "Buy-Through" rate as long as no costs are shifted to other customers. As long as that statement is true and includes provisions that costs not be shifted to the Company, the provision may not be needed.

If the Commission approves any variation of the "Buy-Through" rate that results in a reduced (lost) level of fixed cost recovery, lost fixed costs should be eligible for recovery.

The Company would consider other proposals, but the Lost Fixed Cost Recovery mechanism seems to be the most appropriate method to recover any losses.

Q. What is your understanding of the recommendation on Page 57 of Mr. Solganick's Direct Testimony and on Page 10 of Mr. Broderick's Direct Testimony stating that the DG portion of the lost fixed cost included for recovery in the LFCR should be excluded from loss calculations after the effective date of the proposed three-part rates in this proceeding and eliminated from the LFCR altogether with the next rate case?

A. The Company believes both Staff witnesses misunderstand the level of lost revenues DG will still be generating, even if the three-part rate being proposed by Staff and accepted by the Company is put into effect. The Company does agree that a three-part rate will help mitigate some of the losses associated with DG, but it in no way eliminates them. Staff has recommended a relatively low demand charge be initially established for this three-part rate in order to gradually bring customers into a more modern rate design environment. The Company agrees with this strategy. From the standpoint of gradualism, this makes sense; but a lower demand charge means a higher volumetric charge. And as long as solar production reduces overall retail volumes sold, the recovery of fixed costs is avoided. If in future rate cases the demand charge is increased sufficiently the DG related losses will automatically be reduced and when the rates reduce those losses to an insignificant number, then a consideration of removing them would be appropriate. Until then, the calculation of losses should be specified in the LFCR POA, either with the Company's proposed changes or with the existing methods. If the rate design reduces those losses, the amount requested in the LFCR relating to DG will automatically be reduced as part of these calculations. This is a good thing for both other customers and for the Company, but there is no reason to specify an end date until the rate design supports it.

Q. In the above response you refer to the LFCR POA. Will these changes require a revised POA be submitted once the details of these rate design and LFCR issues are resolved?

A. Yes. The Company has proposed a revised LFCR POA reflecting its proposed changes, but any modification to the Company's original proposal could require further revisions to the POA which might include language to address the transition rates and final three-part rates as separate calculations in future LFCR filings. The revised POA could be submitted with the Company's compliance filing that will be submitted at the conclusion of this proceeding.

Q. Do you wish to address any issues expressed by Staff witness Van Epps?

A. Yes. Mr. Van Epps' testimony is primarily expressing a request for either additional or modified Plan(s) of Administration for the DSM, REST and Transmission Cost Adjustor ("TCA"). Company witnesses Ms. Richardson-Smith and Mr. Tilghman will address the issues with submitting the DSM and REST POAs as part of this proceeding. I will discuss the TCA POA below.

Staff's request relating to the TCA POA is designed to clarify and document changes already discussed by Staff and the Company in the Company's last TCA filing. The Company does not object to the changes and has attached an updated TCA POA as **Exhibit CAJ-R-6**.

III. RESPONSE TO RUCO

Q. What concerns does the Company have with the positions expressed by RUCO witness Mr. Huber?

A. The primary concern the Company has with Mr. Huber's recommendations relate to his objection to increasing the basic service charge. The Company dedicated a substantial amount of its Direct Testimony to explaining and supporting its proposed basic service charge. The Company's CCOSS supported a greater charge. RUCO recommended a residential monthly basic service charge of $12.26 for standard customers and a $14 and $13.63 monthly basic service charge for the TOU rate classes without any specific analysis supporting the lower numbers other than RUCO's concern for gradualism. The data supports at least the $15 monthly charge for the residential class proposed by Staff in conjunction with a three-part rate structure. The Company's witness, Mr. Ed Overcast discusses this in more depth.

Q. What is the Company's position on RUCO's proposals for DG related rates?

A. RUCO has suggested a variety of options for DG customers, including a minimum bill, a demand based rate, standard rate with a declining renewable credit rate, and a no export option. The Company believes Staff's recommended three-part TOU rate is the superior rate for all customers, including DG customers. It is a cost based and cost effective proposal. As proposed, none of RUCO's options adequately address the cost shifts associated with net metering. However, a number of RUCO's proposals could be modified to recover a greater portion of the fixed system costs necessary to serve net metering customers. In addition, a demand rate correlated to system peak does not necessarily assist the Company is recovering its fixed delivery costs since those costs do not change from one period to the next. This rate design approach would only make sense for the recovery of fixed generation costs.

IV. RESPONSE TO AECC

Q. AECC witness Mr. Higgins offered both support for certain Company proposals and a couple of concerns. Do you wish to address those concerns?

A. Yes. Mr. Higgins was generally supportive of the Company's proposed revenue allocations, but he did not like the level of subsidy shown by the CCOSS and thinks the ultimate revenue allocation between the rate classes that left certain inter-class subsidies unaddressed. On Page 4 of his Direct Testimony, he suggests that any reduction in overall revenue requirement be apportioned to the various rate classes based on a 50/50 split, with one half going to subsidy paying classes and the other half going to subsidy receiving classes. The Company has chosen to adjust the revenue requirement allocation between the rate classes in a manner more reflective of Staff's proposal as shown in **Exhibit CAJ-R-1**. While the final revenue allocation proposed by the Company does not add the level of cost to the largest rate classes suggested by Staff, it does move further in that direction than what was originally proposed by the Company. The Company believes the allocation proposed in this rebuttal testimony is a fair compromise. More movement is warranted and if the CCOSS results in future rate cases supports it, we will continue to make proposals that will reduce this subsidy.

Q. Mr. Higgins, on Page 4 of his Direct Testimony, also recommended that approximately $908,000 of the reduction allocated to the subsidy-paying classes be held back and used to fund the "Buy-Through" (Experimental Rider 14) rate. Does the Company's proposal allow for this recommendation?

A. No. As discussed in my Direct Testimony and later in this testimony, the Company does not support the approval of the "Buy-Through" Rider. Mr. Higgins' suggestion still results in costs to serve those participating customers to be shifted to remaining customers.

V. RESPONSE TO NUCOR

Q. Mr. Zarnikau submitted Direct Testimony on behalf of NUCOR who is a customer of the Company. Do you have any concerns with the suggested changes he has offered in that testimony?

A. Yes I do. The specific objections to NUCOR's proposals are as follows:

1. **NUCOR does not agree with the way the LPS demand rates are designed.** Demand rates should be a combination of costs being recovered based on the system's non-coincident peak and its coincident peak depending on the cost. Further review of how these costs should be recovered may justify more costs being allocated to the off-peak period instead of less as NUCOR proposes, especially for the largest TOU rate class. Since the current differential was agreed to in the last rate case, the Company believes its current design is appropriate and is willing to leave the differential as it is in current rates for purposes of this rate case.
2. **NUCOR does not agree with reducing the on and off peak price differential.** The Company does not currently incur a substantial difference in the marginal cost of energy purchased on peak, versus off-peak. Therefore, the Company believes its proposed differential between on- and off-peak fuel prices is appropriate. In fact, the actual difference in marginal costs associated with the on- and off-peak period may justify a smaller differential. But for purposes of this case, the Company is willing to leave the differential as proposed in the Company's direct rate case.
3. **NUCOR believes the Interruptible rate should be redesigned.** The interruptible rate has not provided benefit to the system or other rate payers in the last few years and the capacity needs of the Company do not

justify offering any discount for the interruptible service currently being provided. The Company has proposed a new Interruptible Rider and proposed to freeze the current IPS rate. Staff has agreed to this proposal. Without a need to interrupt during the peak load timeframe, the Company does not see any value in creating a special deal that allows for a discount if the customer can interrupt during the off-peak period.

NUCOR wants the load factor associated with the EDR to be calculated based on the customer's billing demand and monthly usage. The Company's proposal simply states the customer must have a load factor of greater than 75% to qualify. The Company proposed this provision to encourage only the customers with the highest load factor to participate. Changing the parameters in the tariff may result in less efficient use of the system and may result in capacity issues. Therefore the Company does not believe that any changes to the proposed tariff are necessary or appropriate.

The Company has put together a set of proposals in its rate case that are designed to offer a balanced allocation of costs and the recovery of those costs. The Company has suggested many changes to its current tariffs and overall rate design in an attempt to reduce intra- and inter-class subsidies. As circumstances change, many specialty provisions are created that tend to favor a specific group or class of customers. The Company prefers to minimize the occurrence of situations where customers receive special treatment. Some of these situations are warranted and in those cases the Company would like to minimize the subsidies where possible. The Company has attempted to create a CCOSS that fairly allocates costs between the general rate classes. It understands that occasionally specific groups may need special attention, such as low income customers. That being said, the Company does not wish to encourage situations where customers seek special treatment to make their rates lower at the expense of other customers.

Staff is tasked with creating a fair set of rates that are justified and non-discriminatory. Staff is also tasked with creating rates that allow the Company a reasonable opportunity to realize its approved return on the plant it has in service to provide energy and other services to its customers. The Company has proposed a revenue requirement it believes is representative of the amount necessary to achieve that goal. It has also calculated a CCOSS that should be used as a guide to allocate costs to each rate class. With that as the starting point, the Commission must review all of the evidence in the record and decide if it agrees with any individual party or any combination of parties based on that evidence. As that evidence is considered, some thought must be given to the specific parties who express a special interest. This includes the low income customers, solar providers, specific customers such as NUCOR, WalMart, the Fresh Produce customers, and other groups like SWEEP and WRA. All of these groups want the general rate design and cost recovery allocation to benefit their individual interests. The Commission must decide if creating a group of "winners" at the expense of the "losers" (i.e. remaining customers) is in the best interest of the customer base, the service territory or even the State of Arizona. If the Commission believes that allowing a subsidy or special rate design that creates "winners" is in the best interest of their constituents, then they will do so. NUCOR's proposals seem to fall into this special interest category.

The Company recognizes NUCOR is an important customer and as such has proposed a reduced increase to its rate class and has agreed to special provisions that benefitted them in the past. However, in this case the Company does not believe special consideration is justified beyond what was proposed in its original filing, along with any adjustments made to accommodate Staff's recommendations.

As such the Company believes that it is not appropriate or fair to modify the rates and cost allocation for NUCOR.

Q. NUCOR has suggested substantial changes be applied to how the customers in this LPS-TOU rate class are billed demand related charges starting on Page 8, line 4 of Mr. Zarnikau's testimony. Do you agree with his recommended changes?

A. No. As NUCOR's witness states and as Company rebuttal witness Mr. Overcast states, the generation and transmission costs should be based on the capacity needs the customer contributes to the system peak. Even though NUCOR states that the existing tariffs are poorly designed, they do exactly what he suggests. The only concern Mr. Zarnikau has expressed relates to how the demand charge is calculated and the test to determine how the customer should be billed. The peak period demand calculation already reflect his theory and an alternate test allows for one-half of the off peak demand to be used in calculating a customer's bill. This alternate is designed to allow some benefit to customers who peak during the system's off peak period. Billing determinants are based on this theory and have been the guideline in place for this class in all recent rate cases. With only four customers in the LPS rate class this cost allocation and method of recovery is reasonable. NUCOR fails to recognize that through the cost of service process a level of costs is identified and is allocated to the customers in that rate class. NUCOR is the only customer in the TOU class and is currently the Company's largest consumer. Therefore the Company is of the opinion that its allocation of demand related costs is reasonable and any change to how it is recovered would not change the total cost allocated to that class, only how that TOU customer would pay the same total amount. Therefore no change in how demand charges are recovered is warranted.

VI. RESPONSE TO FPAA

Q. Does the Company wish to address concerns expressed by the Fresh Produce witnesses on behalf of customers who take service from the Company in the Nogales area?

A. Yes. The Company recognizes that the Fresh Produce group is important to the Company. Fresh Produce witnesses Jungmeyer and Simer have requested that the ratchet, applicable to the demand charge, be reduced or eliminated in order to reduce what their members pay during their off season.

As also discussed earlier in my testimony, the Company has proposed many changes in this case in an attempt to mitigate inter- and intra-class subsidies. The ratchet was added in the last rate case to help mitigate the intra-class subsidy and is a common method of assigning the actual demand that a customer places on the system. Many times that ratchet is 100%. The Company's current 75% ratchet is a compromise and moves the rates in the direction that improves the allocation and cost recovery from customers within the rate class. If the rate was changed to a more seasonal design that allowed these customers to avoid paying for the cost of their system during the two or three months they operate at a reduced load, any new design would require that they pay more when they place load on the system. If not, the cost of the system used to serve them will be paid by other customers. The Company believes this proposal does just the opposite of what it desires to accomplish in this proceeding, which is to design rates that better allocate cost recovery to the cost causer.

Q. Fresh Produce witness, Mr. Simer also requests that the ratchet be removed. Are his arguments any more compelling?

A. No. Our rebuttal positions apply to his arguments as well. The Company understands this is an important group of customers and considered them when the 75% ratchet was established in the last rate case. Even the witness' graph, on Page 9 of his testimony, shows that for the select group of customers, three of the six peak months the group is at or near 75% of the combined peak of 2700 kW. And the group peaks in June which is coincident with the typical system peak in the Santa Cruz territory. By only allocating demand costs based on 75% of the customer's 11 prior peaks in those three off months, the Company has designed a reasonable compromise in rate design. Any additional movement of costs to other customers would mean the Fresh Produce customers would be subsidized by all other customers in the class during the other nine months of the year. The Company believes the 75% ratchet is appropriate and should remain part of the rate design for this customer class.

VII. RESPONSE TO ACAA AND CARES ISSUES

Q. Ms. Cynthia Zwick, who is testifying on behalf of the ACAA has expressed concerns with how the Company is currently serving the CARES customers and the proposals the Company has made regarding discounts. Would you please respond to these concerns?

A. Yes. Ms. Zwick has discussed the hardships low income customers experience and the Company is sympathetic to these challenges. Under the Company's proposal, CARES customers will receive bill reductions of approximately $1,000,000 annually which maintains the existing discount level. The actual dollar impact on the typical CARES customer is shown on my **Exhibit CAJ-2** to my Direct Testimony and reflects a dollar change that averaged $5.75 for the Standard CARES customer and $6.23 for a CARES medical customer.

Ms. Zwick also suggested the eligibility be expanded to an income level representing 200% of the Federal government's poverty level. The Company proposed to keep the current income qualification level, which is 150% of the Federal Poverty level. She did not specify how many eligible customers would be added, but if this expansion doubled the number of CARES customers from approximately 6,200 to over 12,000, the discounts would also double to approximately $2 million per year. If the Commission approves Ms. Zwick's proposals, the Company would seek to recover those bill discounts exceeding $1 million from other customers through an adjustor mechanism. The Commission could also consider applying the CAREs discount to the base cost of fuel and PPFAC only, resulting in those customers paying lower fuel and purchased power costs. This would result in any incremental costs being shifted to non-CARES customer's through the PPFAC adjustment.

The Company believes Staff's recommendation is the best solution for providing discounts available to CARES customers. The Company would propose provisions consistent with Staff's suggestions, while maintaining the current $1,000,000 discount to the CARES customers and current eligibility criteria. As a result, between rate cases, any increase in participation resulting in discounts above $1 million annually would be incurred by the Company.

Q. Didn't Staff's witness, Mr. Solganick indicate the CARES discount should remain at the current level of just under $600,000 per year?

A. Yes, he did. That amount is reflected in the Company's revenue proof as the percentage and flat discounts included in rates. However, Staff's recommendation, which the

Company agrees to adopt, will be built to offer discounts off of the existing standard residential rate once the proposed three-part rate is approved. This means there is also an increase in the basic service charge from the Company's originally proposed $9.00 per month to $15.00 per month. For approximately 6,200 CARES customer being billed 12 months per year this is another $446,000 of discounts that would need to be added to the current $585,000 of discounts reflected in the revenue proof for total CARES discounts of just over $1,000,000 to keep the customers at the same level as today.

Q. How would the Company design the method to offer discounts to the CARES customers?

A. The numbers will vary depending on the final outcome of this proceeding, but based on the current numbers, the Company is proposing to offer a flat percentage discount to all standard CARES customers of 18% with a flat $16 discount applied for bills reflecting more than 1,000 kWh of consumption and a flat percentage discount to all CARES-Medical customers of 24% with the same flat $16 discount applied for bills reflecting more than 2,000 kWh. The CARES-Medical rate would continue to be frozen so no new customers would be added. The Company calculates that a typical CARES customer using 753 kWh of consumption monthly would see an increase of approximately $5.75 per month. The CARES-Medical increase would be slightly higher at $6.23 per month. The standard CARES customer's bill would still be approximately $170 less per year than the standard residential customer's bill using approximately the same amount of energy. The CARES-Medical bill will be closer to the standard residential customer's annual bill. Even though their typical usage is over 200 kWh more per month the total bill is approximately the same.

Q. Do you believe Staff's proposal is fair to the CARES customers?

A. Yes. Staff suggested this method as a compromise that will let the CARES customers see the amount of their undiscounted bill, even when the new three-part rates become effective. This provides customers with the appropriate pricing signals and will allow them to more easily adapt to the three-part rates when they become effective. The Company believes it is a good solution and still provides a meaningful discount in the CARES customers' bills. By basing a CARES customer's bill on the exact same rates as a standard residential customer, the CARES customers will be included with the rest of the residential class that pay the DSM surcharge as proposed by the Company in it direct case.

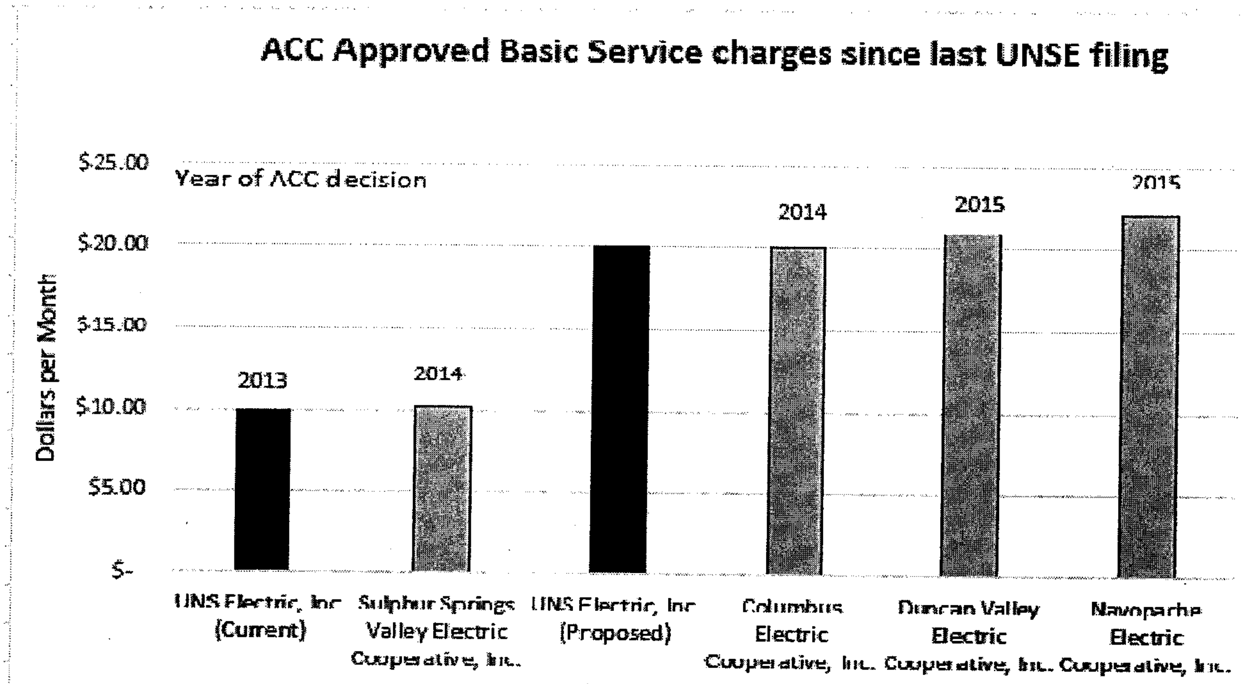
Q. Will the proposed CARES discount method work with the three-part rate the Company has proposed for the residential customers?

A. Yes. However, if after the new rates become effective and an issue is identified, changes can be made during the window created to leave rate design open.

VIII. RESPONSE TO SWEEP

Q. SWEEP witness Mr. Schlegel has filed testimony in opposition to a number of the Company's proposals. Would you like to address his objections?

A. Yes. The Company's rebuttal witness Mr. Overcast does an excellent job of explaining why the increased basic service charge and the elimination of the third tier are appropriate. Also, Mr. Schlegel, on Page 8, line 25 of his testimony indicated the Company's proposed $20 per month basic service charge will be one of the highest in the region. Based on the Company's research, recent Commission actions have approved a number of basic service charges at least as high as the one the Company is requesting. Please refer to the following table:



Q. **What other issues expressed by Mr. Schlegel do you wish to address?**

A. I have already addressed Mr. Schlegel's suggestion to not include generation in the LFCR, and his recommendation to maintain the 1% cap in my testimony rebutting Staff witness Mr. Solganick so I will not discuss it further here. I will also mention that the Company appreciates Mr. Schlegel's testimony justifying a full decoupling mechanism, but believes fixing the LFCR by correcting it in accordance with the changes suggested by the Company in my Direct Testimony will provide the Company with sufficient incentive to continue to promote DG and EE.

IX. <u>RESPONSE TO VOTE SOLAR AND TASC</u>

Q. **Vote Solar witness Ms. Kobor and TASC witness Mr. Fulmer oppose many of the Company's proposals. Did you wish to discuss some of those issues?**

A. Yes. I will address a few of their concerns. The Company's witnesses' Mr. Dukes, Mr. Tilghman, and Mr. Overcast have done a very good job of explaining the flaws in both

Ms. Kobor and Mr. Fulmer's misguided evaluation of how DG customers impact the Company's system and the "real" value they bring to the system.

Q. Ms. Kobor on Page 44 indicates that the LFCR is a better way to recover lost fixed cost than correcting antiquated rate design. Do you agree?

A. No. While I agree that the LFCR is a necessary mechanism while we are transitioning our rates to a more equitable and more modern design, I see the LFCR as a mechanism that furthers the cross subsidy between DG customers and full requirements customers because it transfers the volumetric recovery of costs incurred for DG customers to other customers. The best long-term way to address the lost fixed costs is to get the rate design right. As appropriate rate design is placed into effect, and customers are contributing more appropriately to their portion of the fixed costs, the need for the LFCR will be reduced or it may no longer be necessary for DG related lost fixed cost revenue. Additionally, Ms. Kobor fails to mention that the lost fixed costs generated by the DG customers are not charged back to the DG customers; it is paid by all remaining customers, thereby making the subsidy worse. Unfortunately, until rate design is corrected, recovery through the LFCR is our best option between rate cases.

Q. On Page 50 of Ms. Kobor's testimony she indicates she believes a cost of service study is necessary to increase a net metering customer's rates. Did the Company file a CCOSS in this proceeding?

A. Yes. I find it rather interesting that Vote Solar believes it is necessary to have CCOSS supported information to justify placing DG customers on a three-part rate, given that there was no cost-based justification for providing the net metering customer the subsidized rate that they currently enjoy.

Q. Mr. Fulmer indicates on Page 24 of his Direct Testimony that a minimum bill is a better way of addressing low use customers. RUCO witness Mr. Huber on page 8 of his Direct Testimony and WRA witness Mr. Wilson also suggest a form of minimum bill in their testimony. Is this something the Company would consider?

A. The Company supports the three-part rate for our residential and SGS customers. This is the best option for our customers and moves us further toward appropriate cost recovery. Absent the superior three-part rate as an option, the minimum bill proposal may be something the Company would consider. Even though it is a better option than the current two-part rate, there are issues with the minimum bill as well. These include not sending the right price signals regarding basic service charges or energy charges, bill impacts for low use customers, no signals to incent capacity conservation which potentially results in reduced future adoption of technology to reduce capacity, etc. With appropriate design, it can still be a move in the right direction though.

X. <u>AGS EXPERIMENTAL RIDER 14 ("BUY-THROUGH")</u>

Q. Which Commission Staff and/or Intervenor parties addressed the Company's proposed Experimental Rider 14 in their Rate Design testimony?

A. Commission Staff, AECC, Walmart, and AIC addressed the issue.

Q. Please summarize the Intervenor Parties positions regarding the Company's proposed Experimental Rider 14.

A. Staff is neutral on adoption of Experimental Rider 14 and does not object to its adoption if there are no adverse impacts on non-participating customers. AECC and Walmart support adoption of Experimental Rider 14 with recommended revisions that I will discuss in more detail.

AIC opposes adoption of the Rider because it benefits only the customers fortunate enough to be chosen to participate and shifts costs to non-participating customers. Also, AIC notes that a similar program (AG-1) was implemented by APS in 2012 and the potential effects of that program on the company and its customers are uncertain. AIC recommends that the Commission should wait until it is able to analyze the performance of the APS AG-1 rate program before requiring the implementation of a similar program by UNS Electric.

a. <u>Commission Staff</u>

Q. Please summarize ACC Staff comments on the Company's proposed Experimental Rider 14.

A. Mr. Solganick stated that Staff looks forward to the input of other parties and does not object to the implementation of Experimental Rider 14 if there are no adverse impacts or costs to other customers. In particular, Staff opposes recouping any lost revenue in the LFCR and opposes any deferral of lost revenue.

Q. Do you agree with Staff's position that no lost revenue resulting from the implementation of Experimental Rider 14 should be recovered in the LFCR or deferred for recovery at a later date?

A. As clearly stated in my Direct Testimony, the Company is not supportive of the "Buy-Through" rate. I will discuss the Company's concerns and objections to this rate later in my Rebuttal Testimony. Staff indicated they do not object to a "Buy-Through" mechanism if there are no adverse impacts and no costs to the other customers. This includes not allowing any identified costs to be recovered through the Company proposed method of including it in the LFCR mechanism.

As stated in my Direct Testimony, with regards to the "Buy-Through" rate since UNSE does not have anyone on staff to offer this type of service, providing it will require additional personnel, additional processes to track and verify the flow of energy, incremental Transmission balancing services, additional billing equipment and billing processes, among other things. This will all be required to offer a special deal to a few large customers to gain the opportunity to save on energy while the market is down, only to come back for full retail service when the market returns. Since the fixed cost of the Company's generation facilities are included in base rates and recovered on a test year assumed level of sales, all lost sales due to this program will produce lost fixed cost recovery. We would prefer not creating a potentially subsidized rate for a few select large customers just to create more lost revenues. Therefore, without charging the full retail non-fuel rates while the customer was participating in the "Buy-Through" rate, a loss in revenues will occur. If the rate is approved, there will be a cost. That cost will fall on someone. The Company's goal in this case is to address and minimize subsidized pockets of customers, not create more.

b. AECC

Q. Please summarize AECC's recommendations for proposed Experimental Rider14.

A. AECC witness Kevin Higgins recommends adoption of a buy-through program "that is as similar as reasonably possible to the APS AG-1 program approved for APS."[2] Mr. Higgins favors adopting some of the features of the buy-through program presented by the Company, but recommends changes to program eligibility, the proposed monthly management fee, the mechanics of fixed generation cost recovery, and the terms of return to standard generation service. He also recommends clarification of the program term.

Q. Do you agree with AECC's recommendations for Experimental Rider 14?

A. No. I will address each of AECC's recommendations individually.

[2] Higgins Direct, p. 17, ll. 1-2.

Q. Please summarize AECC's recommendations related to Rider 14 program eligibility.

A. AECC agrees that the Company's proposed program cap of 10 MW should be retained. However, AECC recommends broadening the range of customers eligible to participate by reducing the minimum load size from 2.5 MW to 1 MW (peak demand) and allowing aggregation of smaller loads in the MGS/LGS classes owned by the same corporate entity to achieve the 1 MW threshold. Each single entity aggregated to reach the 1 MW threshold should have experienced a billing demand of at least 200 kW in the previous year to be eligible.

In support of the AECC position, Mr. Higgins cites the APS AG-1 program participation limits as they apply to minimum customer load and aggregation. The APS AG-1 program sets a total participation limit of 200 MW and requires a minimum aggregated peak load of 10 MW or more for customer eligibility. The APS AG-1 program allows customers on its Rate Schedule E32-L to participate through aggregation even though they cannot meet the 10 MW minimum individually and has set aside 50% of the initial capacity for those customers. Mr. Higgins states that the customers on APS Schedule E32-L "roughly corresponds to the UNSE MGS and LGS classes"[3] and uses this as support for his recommendation.

Q. Do you agree with the AECC recommendation to reduce the minimum load size for participation and allow aggregation of corporate loads?

A. No. While the APS AG-1 program can serve as a model for certain elements of a similar program for the Company, the proposal should not be identical to the APS AG-1 program. The Company and APS are utilities of much different size, generating capacity and customer characteristics. In 2014, the APS system had a peak demand approximately 17 times larger than that of the Company. As a result, APS is most likely able to take

[3] Higgins Direct, p. 18, ll. 6-7.

advantage of economies of scale that are not available to a company the size of UNS Electric. The Company does not currently have personnel on staff to manage a program like that proposed in Experimental Rider 14, much less to manage aggregation of corporate loads for such a program as Mr. Higgins is proposing.

Also, APS Schedule E32-L is applicable to customers whose average monthly maximum demand is greater than 400 kW and the Company's MGS tariff specifies a minimum monthly billing demand of 20 kW. A minimum size customer on APS Schedule E32-L is 20 times larger than a minimum size customer in the Company's MGS rate class. The APS E32-L rate class in no way corresponds to the MGS rate class.

Finally, the order in the Fortis acquisition of UNS Energy, parent of TEP and the Company specifies that in their next rate cases "TEP and UNS Electric will propose a pilot program for a "buy through" tariff available to Large Light and Power Service and Large Power Service customers, respectively."[4] As mentioned earlier, the Company is proposing Experimental Rider 14 as a condition of the Fortis merger settlement agreement, but is not supporting its adoption. Therefore, the Company sees no reason to expand the availability of Experimental Rider 14 beyond the customer classes specified in the Fortis merger settlement agreement.

Q. Do you agree with AECC that the Company's proposed monthly management fee should be reduced from the $0.004/MWh to $0.0006/MWh which is the management fee specified in the APS AG-1 rate rider?

A. No. The only reason Mr. Higgins gives for the Company's proposed management fee being "unreasonable and exorbitant" is that it is "six times greater" than the APS

[4] ACC Decision No. 74689, Opinion and Order in Docket No. E-04230A-14-0011, Attachment A, p. 5, August 12, 2014.

management fee. As mentioned earlier, APS and the Company are much different companies especially where size is concerned. APS, with a 2014 peak demand roughly 17 times that of the Company, likely has scale economies that do not exist for the Company. Therefore, a higher charge for the service is reasonable.

Furthermore, APS has indicated that the net impact of the AG-1 program has been losses in the range of $10 million annually.[5] Rather than the proposed management fee being "unreasonable and exorbitant" it is highly likely that the APS AG-1 management fee is inadequate and partly responsible for the AG-1 program losses.

Q. Please summarize Mr. Higgins recommendations regarding the Company's fixed generation cost recovery.

A. The Company proposed that participating customers pay 100% of the customer's generation-related demand component for all billing demand for the first twelve months of service and 25% for the remainder of service under the Rider. Mr. Higgins recommends that charges for generation-related services should be limited to a charge for reserve capacity applied to 15% of the customer's billed demand priced at the unbundled generation demand charge. Essentially, Mr. Higgins is recommending that the recovery of generation-related fixed costs from participating customers be reduced from the Company's proposal of 100% in the first year, and 25% thereafter to 15% for the entire term of service under the Rider.

Q. What are AECC's objections to the Company's proposed recovery of fixed generation costs from participating customers?

A. Mr. Higgins argues that while some assignment of cost for generation reserves may be appropriate, the Company's proposal is excessive and is more comparable to a stranded

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[5] ACC Decision No. 75322, Order in Docket No. E-01345A-11-0224, p. 2, November 25, 2015.

cost charge. He argues that the stranded cost approach should be rejected unless the customers are being provided with an opportunity to transition permanently to market pricing. Mr. Higgins bases his recommendation of 15% on the Company's planning reserve margin.

Q. Do you agree that the Company's proposal is comparable to a stranded cost charge?

A. No. Stranded cost is defined as the net present value difference between the market value of an asset and the book value. If the market value is less than book, stranded costs result. In other words, a stranded cost calculation would look at the entire value of the asset up to the time the asset is retired. The Company has invested in generation assets to serve all customers on the system including those who might participate in the Rider 14 program. The capital costs related to these generation assets are collected from the customers served by them over the useful life of the assets. A recovery of 100% of fixed generation costs for one year is not equivalent to a stranded cost charge, which would be calculated over the entire remaining life of the asset. In fact, the fixed generation costs reflected in rates are set to recover that assets depreciation expense and return for the life of generation assets on a monthly basis over the life of those assets. Recovering 100% of those costs over a 12-month period would be much less than a system exit fee based on stranded costs.

Q. Do you agree with Mr. Higgins' suggestion that the first $908,000 of any revenue requirement reduction should be apportioned to "subsidy-paying" classes to help absorb any UNS Electric revenue deficiency ascribed to lost generation revenues?

A. No. As discussed in my Direct Testimony and in this Rebuttal Testimony, the Company does not support the approval of the "Buy-Through" Rider 14. Mr. Higgins' suggestion is innovative on the surface, but still results in the costs associated with providing the "Buy Through" option to a select few customers coming out of the Company's total revenue requirement and thereby being paid for by the remaining customers.

Q. Do you agree with Mr. Higgins that the price for returning to full utility service should be lowered from the Company's proposed Dow Jones Palo Verde Index plus $20/MWh to the Index plus a maximum of $4/MWh?

A. No. This charge is being proposed to discourage this from happening. Therefore the penalty charge needs to be large enough to make that happen. Hopefully, the charge will never be applied, but if it is it needs to be a true penalty. The APS AG-1 program specifies the Dow Jones Palo Verde Index plus $10/MWh. Reducing the adder to $4/MWh has no justification. Again, UNS Electric wants to protect itself and its customers from the types of losses that APS has experienced as a result of its AG-1 program.

Q. What are AECC's recommendations with respect to clarification of the Experimental Rider 14 program term?

A. AECC recommends that the program term should be restated to indicate that Rider 14 will continue to be available at least until the start of the first rate-effective period following a general rate case occurring no less than four years from the program start date.

Q. What is AECC's justification for this recommendation?

A. While Mr. Higgins states that he does not disagree with the Company's proposal to target a four-year period for the program term, he believes it is important that any program extension or modification be considered in the context of a future general rate case prior to termination of the program.

Q. Do you agree with the AECC recommendation to extend the program term at least until the start of the first rate-effective period following a general rate case occurring no less than four years from the program start date?

A. No. If the Company is ordered to implement Rider 14 it should be for a maximum of the four years specified in the tariff. AECC seems to want the best of both worlds with this recommendation.

c. Walmart

Q. Please summarize Walmart's recommendations for proposed Experimental Rider 14.

A. Walmart witness Chris Hendrix recommends approval of Experimental Rider 14 with the following changes:

- UNS Electric's proposed management fee of $0.004/kWh should be rejected and the Company should be required to file a cost-justified management fee proposal.
- The minimum participation level should be reduced to 1,000 kW and corporate aggregation should be allowed to meet the limit.
- All rate classes should be allowed to participate in the program.
- The total participation limit should be raised to 150 MW, based on the amount of wholesale electricity purchases currently undertaken by UNS Electric.
- Experimental Rider 14 customers should not be responsible for any of the Company's generation related charges because the program is simply replacing market purchases.
- There should be no limit on the term of the program.

Q. Do you agree with Walmart's recommendations for Experimental Rider 14?

A. No. I will address Walmart's recommendations individually.

Q. Do you agree with the Walmart's recommendation to reject the Company's proposed management fee and require UNS Electric to file a cost-justified management fee proposal?

A. No. Proposed Experimental Rider 14 is an optional program. If any potential participants believe the management fee is too high, they can elect not to participate. Since the level of participation and therefor the level of personnel necessary to monitor the program, nor the equipment or software needs are known at this time, the initial charge should be large enough to capture any and all possible costs. The Company believe the proposed $0.004 per kWh meets those needs.

Q. Do you agree that the minimum participation level should be reduced to 1,000 kW and corporate aggregation should be allowed to meet the limit?

A. No. As I addressed in the rebuttal to AECC concerning this issue, UNS Electric does not have the resources to deal with smaller customer sizes than specified in the proposed Rider 14 or aggregation of loads.

Q. Do you agree with Walmart's recommendation that all rate classes be allowed to participate?

A. No. As mentioned earlier, the Fortis acquisition settlement agreement specified only that UNS Electric make a program like that proposed in Rider 14 available to customers in the Large Power Service rate class.

Q. What is Walmart's basis for recommending that the total participation cap be raised to 150 MW?

A. Mr. Hendrix notes that according to the Direct Testimony of UNS Electric witness Michael E. Sheehan, the Company will be purchasing 175 MW of Market Based Resources after the Gila River Acquisition. Mr. Hendrix bases the 150 MW cap recommendation on that number and argues that removing that 150 MW from the Company's market purchases would "significantly reduce the Company's reliance on the wholesale market and transfer the market risk to customers who are willingly participating in the AGS program."[6]

Q. Do you agree with Mr. Hendrix that the total participation cap should be raised to 150 MW?

A. No. Mr. Hendrix's recommendation ignores the entire process of Integrated Resource Planning. An Integrated Resource Plan ("IRP") is a utility plan for meeting forecasted annual peak and energy demand, plus an established reserve margin, through a combination of supply-side and demand-side resources over a specified future period. It is a dynamic process and a utility's IRP will typically be examined, modified, and acknowledged in a proceeding before a regulatory commission.

The Company's IRP was developed via extensive modeling and dynamic optimization to select the best combination of supply and demand-side resources to serve projected Company loads plus a reserve margin. Also, the Company's IRP has been reviewed and acknowledged in a separate IRP proceeding by the Commission. Mr. Hendrix proposes to throw out that entire process and make ad hoc adjustments to the Company's IRP in a rate case, not in a proceeding where these planning issues are more closely examined.

Finally, the 175 MW of market power purchases cited earlier in the Company's IRP has not been planned for the sole benefit and use of prospective Rider 14 customers. In the same vein, the Gila River Acquisition was undertaken to benefit all customers on the system. Prospective Rider 14 customers should not be allowed to evade their responsibility for cost recovery of the utility's fixed generation assets that were procured to their benefit under an obligation to serve.

[6] Walmart-Hendrix Direct, pp. 7-8, ll. 20-1.

Q. Do you agree with Walmart's statement that Experimental Rider 14 customers should not be responsible for any of Company's generation related charges because the program is simply replacing wholesale market purchases?

A. No. The generation related charges included in rates are not avoidable. For the same reasons that I believe the generation costs should be included in the LFCR rates, I believe these customers should be required to pay the level of generation costs they were allocated in the most recent rate case. All resources that the Company relies on to serve loads on the system are procured for the benefit of all customers. All customers should therefore be responsible for their share of allocated costs.

Q. Do you agree that the program term should be unlimited?

A. No. "Experimental" means a program that has to be tested and evaluated to determine whether it merits becoming a permanent rate structure. As mentioned earlier, the Fortis Acquisition Settlement specified that UNS Electric propose a pilot program for a buy-through tariff. Pilot programs by definition are of limited duration.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Exhibit CAJ-R-1

UNS Electric, Inc.
Summary of Revenues by Customer Classifications
Adjusted Present Rates And Proposed Rates
Test Period Ended December 31, 2014

Line No.	Class of Service	Test Year Present Net Revenue	Net Change	Proposed % Increase to Test Year	Adjusted TY Revenue	Proposed Dollar Increase (a)	Proposed Percent Increase to Adjusted Test Year Revenues (a)	Proposed Net Revenue
1	Residential Service	$83,768,709	$10,172,880	12.1%	$78,169,265	$15,928,289	20.38%	$94,097,555
2	Small General Service	12,922,488	1,355,249	10.5%	12,461,200	1,816,538	14.58%	14,277,738
3	Interruptible Power Service	2,920,047	277,930	9.5%	3,111,532	86,446	2.78%	3,197,977
4	Medium General Serive	0	45,117,600	0.0%	0	45,117,600	0.0%	45,117,600
5	Large General Service	46,292,475	-37,043,568	-80.0%	43,498,604	-34,243,500	-78.72%	9,255,104
6	Large Power Service	21,454,373	-14,756,700	-68.8%	17,170,539	-10,393,742	-60.53%	6,776,797
7	Lighting	528,359	94,271	17.8%	547,038	75,592	13.82%	622,630
8	Subtotal	$167,886,452	$5,217,663	3.11%	$154,958,178	$18,387,223	11.87%	$173,345,402
9	Other Operating Revenue	1,734,044	95,034	N/A	1,829,078	N/A	N/A	1,829,078
10	Total	$169,620,496	$5,312,697	3.13%	$156,787,256	$18,387,223	11.73%	$175,174,479

Total Electric Retail Service
(a) H-2 (P2)

Recap Schedules
A-1

Exhibit CAJ-R-2

UNS Electric Inc.
Bill Impacts
Test Period Ending December 31, 2014

Line No.	Class Description	Customer Counts To-date (Dec 2015)	TEST YEAR ADJUSTED WITH MARGIN INCREASE, FUEL/PPAFC TRUE-UP AND TCA			TEST YEAR ADJUSTED WITH MARGIN INCREASE, FUEL/PPAFC TRUE-UP, TCA AND DEFERRED CREDIT			COS RETURNS
			Annual Bill Change	Monthly Bill Change	Percent Change to Total Bill With Fuel Increase	Annual Bill Change	Monthly Bill Change	Percent Change to Total Bill With Fuel Increase	
1	Residential	75,504	$79.24	$6.60	**7.78%**	$18.34	$1.53	**1.76%**	
2	Residential CARES	5,904	$69.00	$5.75	**9.04%**	$23.52	$1.96	**3.01%**	
3	Residential CARES-M	251	$74.78	$6.23	**7.96%**	$19.15	$1.60	**1.99%**	6.45%
4	Residential TOU	266	$102.04	$8.50	**8.61%**	$27.82	$2.32	**2.29%**	
5	Residential TOU Super Peak	5	$102.76	$8.56	**8.92%**	$28.66	$2.39	**2.43%**	
6	Small General Service	8,839	$155.11	$12.93	**10.67%**	$74.65	$6.22	**5.02%**	
7	Small General Service TOU	14	$219.45	$18.29	**9.31%**	$75.09	$6.26	**3.11%**	6.34%
8	Interruptible Service	25	$14,823.67	$1,235.31	**16.99%**	$7,865.17	$655.43	**8.72%**	
9	Medium General Service	1279	$909.85	$75.82	**2.79%**	($1,002.53)	($83.54)	**-3.00%**	
10	Medium General Service TOU	9	$1,855.86	$154.66	**2.29%**	($2,868.72)	($239.06)	**-3.44%**	
11	Large General Service	10	($2,353.68)	($196.14)	**-0.47%**	($35,891.52)	($2,990.96)	**-6.99%**	18.59%
12	Large General Service (Formally LPS)	7	($14,102.18)	($1,175.18)	**-2.77%**	($47,640.02)	($3,970.00)	**-9.07%**	
13	Large General Service TOU	2	$15,412.80	$1,284.40	**2.29%**	($30,637.62)	($2,553.14)	**-4.41%**	
14	Large Power Service	3	$31,961.74	$2,663.48	**2.37%**	($69,774.86)	($5,814.57)	**-4.99%**	
15	Large Power Service TOU	1	$55,198.74	$4,599.90	**2.61%**	($94,037.58)	($7,836.47)	**-4.32%**	17.18%
16	Lighting Service	1,922	$31.80	$2.65	**19.94%**	$28.92	$2.41	**18.13%**	10.41%

UNS Electric Inc.
Bill Impacts
Test Period Ending December 31, 2014

Line No.	Class Description	Customer Counts To-date (Mar 2015)	New Summer Month A	Total Summer Change B	Summer Change C=(B*6)	New Winter Month D	Total Winter Change E	Winter Change F=(E*6)	Annual Bill G=(A*6+D*6)	TEST YEAR ADJUSTED - FUEL TRUE-UP AND MARGIN INCREASE: Annual Bill Change	Monthly Bill Change	Percent Change to Total Bill With Fuel Increase
1	Residential	75,504	$100.68	$0.48	$2.88	$76.17	$2.58	$15.46	$1,061.11	$18.34	$1.53	**1.76%**
2	Residential Demand		$103.59	($4.25)	($25.52)	$76.26	($4.41)	($26.45)	$1,079.10	($51.97)	($4.33)	**-4.59%**
3	Residential CARES	5,904	$75.38	$1.89	$11.34	$58.93	$2.03	$12.18	$805.84	$23.52	$1.96	**3.01%**
4	Residential Cares Demand		$76.61	($2.82)	($16.92)	$60.37	($1.49)	($8.94)	$821.88	($25.86)	($2.16)	**-3.05%**
5	Residential CARES-M	251	$92.35	$1.51	$9.07	$71.22	$1.68	$10.08	$981.46	$19.15	$1.60	**1.99%**
6	CARES Medical Demand		$92.23	($5.09)	($30.54)	$71.30	($3.63)	($21.78)	$981.18	($52.32)	($4.36)	**-5.06%**
7	Residential TOU	266	$121.20	$2.60	$15.58	$85.62	$2.04	$12.24	$1,240.92	$27.82	$2.32	**2.29%**
8	Residential TOU Demand		$121.29	($7.70)	($46.20)	$82.49	($3.13)	($18.78)	$1,222.68	($64.98)	($5.42)	**-5.05%**
9	Residential TOU Super Peak	5	$117.12	($0.22)	($1.34)	$84.32	$5.00	$30.00	$1,208.64	$28.66	$2.39	**2.43%**
10	Small General Service	8,839	$140.64	$4.95	$29.72	$119.82	$7.49	$44.93	$1,562.76	$74.65	$6.22	**5.02%**
11	Small General Service Demand		$139.11	($9.11)	($54.67)	$118.34	($7.30)	($43.80)	$1,544.70	($98.47)	($8.21)	**-5.99%**
12	Small General Service TOU	14	$236.59	$4.21	$25.24	$178.40	$8.31	$49.85	$2,489.94	$75.09	$6.26	**3.11%**
13	Small General Service TOU Demand		$211.89	($39.11)	($234.66)	$153.40	($25.00)	($150.00)	$2,191.74	($384.66)	($32.06)	**-14.93%**
14	Interruptible Service	25	$9,012.88	$745.31	$4,471.84	$7,333.76	$565.56	$3,393.33	$98,079.85	$7,865.17	$655.43	**8.72%**
15	Medium General Service	1279	$2,946.29	($100.05)	($600.28)	$2,459.78	($67.04)	($402.25)	$32,436.42	($1,002.53)	($83.54)	**-3.00%**
16	Medium General Service TOU	9	$6,818.46	($421.68)	($2,530.08)	$6,591.53	($56.44)	($338.64)	$80,459.94	($2,868.72)	($239.06)	**-3.44%**
17	Large General Service	10	$38,400.51	($2,990.96)	($17,945.76)	$41,195.33	($2,990.96)	($17,945.76)	$477,575.09	($35,891.52)	($2,990.96)	**-6.99%**
18	Large General Service (Formally LPS)	7	$38,400.51	($3,970.00)	($23,820.01)	$41,195.33	($3,970.00)	($23,820.01)	$477,575.09	($47,640.02)	($3,970.00)	**-9.07%**
19	Large General Service TOU	2	$55,512.50	($3,597.95)	($21,587.70)	$55,112.87	($1,508.32)	($9,049.92)	$663,752.22	($30,637.62)	($2,553.14)	**-4.41%**
20	Large Power Service	3	$106,491.04	($5,814.57)	($34,887.43)	$114,969.09	($5,814.57)	($34,887.43)	$1,328,760.75	($69,774.86)	($5,814.57)	**-4.99%**
21	Large Power Service TOU	1	$177,202.48	($7,693.78)	($46,162.68)	$170,341.02	($7,979.15)	($47,874.90)	$2,085,261.00	($94,037.58)	($7,836.47)	**-4.32%**
22	Lighting Service	1,922	$15.70	$2.41	$14.46	$15.70	$2.41	$14.46	$188.40	$28.92	$2.41	**18.13%**

Exhibit CAJ-R-3

Exhibit CAJ-R-3

UNS Electric Inc.
IPS VS. LGS BILL
Test Period Ending December 31, 2014

Billing Determinants

	LF	
kWh		98,000
kW	0.50	268

INTERRUPTIBLE POWER SERVICE	***Rates***	***Revenue***
Basic Service Charge	$18.00	$18.00
Demand Charge, per kW	$5.00	$1,342.47
Energy Charge, per kWh	$0.019408	$1,901.98
TCA, per kW	$1.229700	$330.17
Base Power	$0.043760	$4,288.48
Net Bill		$7,881.10
5713 LARGE GENERAL SERVICE		
Basic Service Charge	$50.00	$50.00
Demand Charge, per kW	$12.81	$3,439.40
Energy Charge, per kWh	$0.005470	$536.06
TCA, per kW	$1.229700	$330.17
Base Power	$0.056603	$5,547.09
Net Bill		$9,902.72
Subsidy		**$2,021.62**

Exhibit CAJ-R-4

UNS Electric, Inc.
Summary of Revenues by Customer Classifications
Adjusted Present Rates And Proposed Rates
Test Period Ended December 31, 2014

Line No.	Class of Service	Test Year Present Net Revenue	Net Change	Proposed % Increase to Test Year	Adjusted TY Revenue	Proposed Dollar Increase (a)	Proposed Percent Increase to Adjusted Test Year Revenues (a)	Proposed Net Revenue
1	Residential Service	$83,768,709	$10,172,880	12.1%	$78,169,265	$15,928,289	20.38%	$94,097,555
2	Small General Service	12,922,488	1,355,249	10.5%	12,461,200	1,816,538	14.58%	14,277,738
3	Interruptible Power Service	2,920,047	277,930	9.5%	3,111,532	86,446	2.78%	3,197,977
4	Medium General Serive	0	45,117,600	0.0%	0	45,117,600	0.0%	45,117,600
5	Large General Service	46,292,475	-37,043,568	-80.0%	43,498,604	-34,243,500	-78.72%	9,255,104
6	Large Power Service	21,454,373	-14,756,700	-68.8%	17,170,539	-10,393,742	-60.53%	6,776,797
7	Lighting	528,359	94,271	17.8%	547,038	75,592	13.82%	622,630
8	Subtotal	$167,886,452	$5,217,663	3.11%	$154,958,178	$18,387,223	11.87%	$173,345,402
9	Other Operating Revenue	1,734,044	95,034	N/A	1,829,078	N/A	N/A	1,829,078
10	Total	$169,620,496	$5,312,697	3.13%	$156,787,256	$18,387,223	11.73%	$175,174,479

Total Electric Retail Service
(a) H-2 (P2)

Recap Schedules
A-1

UNS Electric, Inc.
Comparisons of Sales by Rate Schedules
Present And Proposed Rates
Test Period Ended December 31, 2014

Line No.	Class of Service	Rate Schedule Present	Proposed [1]	Actual kWh Sales	Actual Average Number of Customers	Actual Average kWh per Customer	Test Year End Sales Adjustments	Adjusted kWh Sales	Adjusted Average Number of Customers	Adjusted Average Sales per Customer	Tariff Changes kWh Sales	Tariff Changes Average Number of Customers	Tariff Changes Average Sales per Customer
1	Residential Cares	CARES	NC	57,138,737	6,112	9,349	1,701,588	58,840,325	6,236	9,436	58,840,325	6,236	9,436
2	Residential Service	RES-01	NC	755,005,617	75,847	9,954	6,209,782	761,215,400	76,035	10,011	761,215,400	76,035	10,011
3	Residential Service TOU	RES-TOU	NC	2,731,217	230	11,892	321,911	3,053,127	257	11,880	3,053,127	257	11,880
4	Res Bright Community Solar	RES-BC	NC	844,333	79	10,733	0	844,333	79	10,733	844,333	79	10,733
5	Residential Unbilled			(484,060)	0			0	0		0	0	
6	Small General Service	SGS-10	NC	118,754,401	8,704	13,643	(253,035)	118,501,366	8,750	13,543	118,501,366	8,750	13,543
7	Small General Service TOU	SGS-TOU	NC	170,628	8	22,750	11,802	182,430	8	22,804	182,430	8	22,804
8	Interruptible Power Service	IPS	NC	38,106,302	32	1,193,931	(2,538,461)	35,567,841	29	1,226,477	35,567,841	29	1,226,477
9	Medium General Service		MGS	0	0	0	0	0	0	0	408,462,296	1,331	306,884
10	Medium General Service TOU		MGS-TOU	0	0	0	0	0	0	0	7,718,956	8	964,869
11	Large General Service	LGS	LGS	448,678,574	1,361	329,688	(2,896,080)	445,782,493	1,341	332,425	95,412,304	17	5,612,488
12	Large General Service TOU	LGS-TOU	LGS TOU	3,834,211	5	821,617	3,884,745	7,718,956	8	964,869	15,418,264	2	7,709,132
13	LGS Bright Community Solar	LGS-BC	MGSBC	16,769	3	5,590	(16,769)	0	0	0	0	0	0
14	Large General Service Unbilled			384,473	0			0	0		0	0	
15	Large Power Service & TOU <69 kV	LPS/LPS TOU	LGS/LGS TOU	92,705,606	12	7,672,188	(19,195,235)	73,510,371	9	8,167,819	0	0	0
16	LPS Standard/Mining & TOU >69 kV	LPS/LPSM/ LPS TOU	NC	157,107,744	6	26,184,624	(64,342,470)	92,765,274	4	23,191,318	92,765,274	4	23,191,318
17	Large Power Service Unbilled			(369,148)	0			0	0		0	0	
18	Lighting	LTG	NC	2,820,013	2,388	1,181	7,237	2,827,250	2,388	1,184	2,827,250	2,388	1,184
19	Total Electric Retail Service			1,677,445,418	94,785	17,697	(77,104,986)	1,600,809,167	95,144	16,825	1,600,809,167	95,144	16,825

Note:
[1] NC equals No Change

UNS Electric, Inc.
Comparisons of Revenues by Rate Schedules
Present And Proposed Rates
Test Period Ended December 31, 2014

Line No.	Class of Service	Proposed	Unadjusted [1] Margin Revenue	Unadjusted [2] Fuel & PPFAC Revenue	Margin Pro Forma Adjustment	Fuel & PPFAC [3] Pro Forma Adjustment	Adjusted Margin Revenue	Adjusted Fuel & PPFAC Revenue	Adjusted TY Revenues	Proposed Revenue	Proposed Increase To TY Revenue		Proposed Increase to Adjusted Revenue [4]	
											$	%	$	%
1	Residential Cares	RES-01	$1,779,128	$3,029,378	$0	$0	$1,793,740	$2,585,159	$4,378,898	$5,495,550	$687,045	14.29%	$1,116,652	20.32%
2	Residential Service	RES-01	31,759,612	46,999,721	0	0	31,469,845	41,935,733	73,405,578	88,170,239	9,410,907	11.95%	14,764,661	16.75%
3	Residential Service TOU	RES-TOU	116,271	152,725	0	0	128,000	169,535	297,536	328,290	59,294	22.04%	30,754	9.37%
4	Res Bright Community Solar	RES-BC	34,190	53,651	0	0	33,602	53,651	87,253	103,476	15,635	17.80%	16,223	15.68%
5	Residential Unbilled		110,955	-266,920	0	0	0	0	0	0	0	0.00%	0	0.00%
6	Small General Service	SGS-10	6,255,704	6,650,173	0	0	6,127,602	6,314,938	12,442,540	14,257,815	1,351,938	10.48%	1,815,275	12.73%
7	Small General Service TOU	SGS-TOU	8,527	8,085	0	0	8,992	9,668	18,660	19,923	3,311	19.93%	1,263	6.34%
8	Interruptible Power Service	IPS	1,335,391	1,584,656	0	0	1,223,235	1,888,297	3,111,532	3,197,977	277,930	9.52%	86,446	2.70%
9	Medium General Service	MGS	0	0	0	0	0	0	0	44,466,094	44,466,094	n/a	44,466,094	100.00%
10	Medium General Service TOU	MGS-TOU	0	0	0	0	0	0	0	651,506	651,506	n/a	651,506	100.00%
11	LGS Bright Community Solar	LGS-BC	898	976	0	0	0	0	0	0	0	0.00%	0	0.00%
12	Large General Service	LGS	21,574,476	24,416,757	0	0	21,103,440	21,766,956	42,870,396	7,890,233	(38,101,000)	-82.84%	(34,980,163)	-443.33%
13	Large General Service TOU	LGS - TOU	121,380	186,059	0	0	254,632	373,576	628,208	1,364,871	1,057,432	343.95%	736,663	53.97%
14	General Service Unbilled		138,446	-146,516	0	0	0	0	0	0	0	0.00%	0	0.00%
15	Large Power Service & LPS TOU <69 kV	LPS <69	5,072,348	3,652,261	0	0	3,813,388	5,910,483	9,723,871	0	(8,724,609)	-100.00%	(9,723,871)	0.00%
16	Large Power Service Unbilled		-31,928	-47,197	0	0	0	0	0	0	0	0.00%	0	0.00%
17	Large Power Service & LPS TOU >69 kV	LPS >69	6,894,832	5,914,057	0	0	3,191,840	4,254,829	7,446,668	6,776,797	(6,032,091)	-47.09%	(669,871)	-9.88%
18	Lighting	LTG	505,944	22,415	0	0	505,944	41,094	547,038	622,630	94,271	17.84%	75,592	12.14%
19	Total Electric Service		$75,676,172	$92,210,280	$0	$0	$69,654,260	$85,303,919	$154,958,178	$173,345,402	$5,217,663	3.11%	$18,387,223	11.87%

Note:
(1) Test Year Billed Margin Revenues calculated $69,916 more than Booked Revenues.
(2) Test Year Billed Fuel and PPFAC revenues calculated $175,930 less than Booked Revenues.
(3) Test Fuel and PPFAC Test Year True-up includes a Billed to Book adjustment of $175,930.
(4) Total increase is $69,916 less than Schedule A1, Line 10 due to difference from Test Year billed to booked revenues.

UNS Electric, Inc.
Comparison of Present and Proposed Rates
Test Year Ended December 31, 2014

	Present Rate	Proposed Rate	Increase $	Increase %
Residential Service - CARES - *Transition Rates*				
Basic Service Charge	$4.90	$9.00	$4.10	83.67%
Energy Charge 1st 400 kWhs	$0.018973	$0.030800	$0.011827	62.34%
Energy Charge, all additional kWhs	$0.035400	$0.050800	$0.015400	43.50%
Base Power Supply Charge, all kWhs	$0.061700	$0.050260	-$0.011440	-18.54%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Residential Service CARES Demand				
Basic Service Charge	N/A	$15.00	N/A	N/A
Demand Charge, per kW	N/A	$5.15	N/A	N/A
Energy Charge (kWhs)	N/A	$0.016760	N/A	N/A
Base Power Supply Charge, Summer On-Peak all kWhs	N/A	$0.102251	N/A	N/A
Base Power Supply Charge, Summer Off-Peak all kWhs	N/A	$0.042830	N/A	N/A
Base Power Supply Charge, Winter On-Peak all kWhs	N/A	$0.082800	N/A	N/A
Base Power Supply Charge, Winter Off-Peak all kWhs	N/A	$0.038610	N/A	N/A
PPFAC[1]	N/A	$0.000000	N/A	N/A
Residential Service - *Transition Rates*				
Basic Service Charge	$10.00	$15.00	$5.00	50.00%
Energy Charge 1st 400 kWhs	$0.019300	$0.032258	$0.012958	67.14%
Energy Charge 401-1,000 kWhs	$0.034350	$0.042258	$0.007908	23.02%
Energy Charge, all additional kWhs	$0.038499	$0.060258	$0.021759	56.52%
Base Power Supply Charge, all kWhs	$0.064510	$0.055090	-$0.009420	-14.60%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Residential Service Time-of-Use - *Transition Rates*				
Basic Service Charge	$11.50	$15.00	$3.50	30.43%
Energy Charge 1st 400 kWhs	$0.030350	$0.036900	$0.006550	21.58%
Energy Charge 401-1,000 kWhs	$0.030350	$0.036900	$0.006550	21.58%
Energy Charge, all additional kWhs	$0.030350	$0.036900	$0.006550	21.58%
Base Power Supply Charge, Summer On-Peak all kWhs	$0.129605	$0.111001	-$0.018604	-14.35%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.039605	$0.042830	$0.003225	8.14%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.129605	$0.091550	-$0.038055	-29.36%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.031385	$0.038610	$0.007225	23.02%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Residential Service Demand				
Basic Service Charge	N/A	$15.00	N/A	N/A
Demand Charge, per kW	N/A	$5.15	N/A	N/A
Energy Charge (kWhs)	N/A	$0.016760	N/A	N/A
Base Power Supply Charge, Summer On-Peak all kWhs	N/A	$0.102251	N/A	N/A
Base Power Supply Charge, Summer Off-Peak all kWhs	N/A	$0.042830	N/A	N/A
Base Power Supply Charge, Winter On-Peak all kWhs	N/A	$0.082800	N/A	N/A
Base Power Supply Charge, Winter Off-Peak all kWhs	N/A	$0.038610	N/A	N/A
PPFAC[1]	N/A	$0.000000	N/A	N/A
Residential Service Time-of-Use Super Peak - *Transition Rates*				
Basic Service Charge	$11.50	$15.00	$3.50	30.43%
Energy Charge 1st 400 kWhs	$0.025000	$0.032258	$0.007258	29.03%
Energy Charge, all additional kWhs	$0.035000	$0.042258	$0.007258	20.74%
Base Power Supply Charge, Summer On-Peak all kWhs	$0.170000	$0.159790	-$0.010210	-6.01%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.039700	$0.040810	$0.001110	2.80%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.150000	$0.159790	$0.009790	6.53%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.038700	$0.040810	$0.002110	5.45%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%

	Present Rate	Proposed Rate	Increase $	Increase %
Small General Service - ***Transition Rates***				
Basic Service Charge	$14.50	$30.00	$15.50	106.90%
Energy Charge 1st 400 kWh	$0.030176	$0.032400	$0.002224	7.37%
Energy Charge 401 -7,500 kWh	$0.041042	$0.042400	$0.001358	3.31%
Energy Charge >7,500 kWh	$0.076042	$0.077400	$0.001358	1.79%
Base Power Supply Charge, all kWhs	$0.058241	$0.053290	-$0.004951	-8.50%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Small General Service Demand				
Basic Service Charge	N/A	$30.00	N/A	N/A
Demand Charge, per kW	N/A	$5.49	N/A	N/A
Energy Charge (kWhs)	N/A	$0.016680	N/A	N/A
Base Power Supply Charge, Summer On-Peak all kWhs	N/A	$0.084570	N/A	N/A
Base Power Supply Charge, Summer Off-Peak all kWhs	N/A	$0.045800	N/A	N/A
Base Power Supply Charge, Winter On-Peak all kWhs	N/A	$0.083570	N/A	N/A
Base Power Supply Charge, Winter Off-Peak all kWhs	N/A	$0.040036	N/A	N/A
PPFAC[1]	N/A	$0.000000	N/A	N/A
Small General Service Time-of-Use - ***Transition Rates***				
Basic Service Charge	$16.50	$30.00	$13.50	81.82%
Energy Charge 1st 400 kWh	$0.030176	$0.032400	$0.002224	7.37%
Energy Charge 401 -7,500 kWh	$0.043176	$0.042400	-$0.000776	-1.80%
Energy Charge >7,500 kWh	$0.076042	$0.077400	$0.001358	1.79%
Base Power Supply Charges				
Base Power Supply Charge, Summer On-Peak all kWhs	$0.129605	$0.109800	-$0.019805	-15.28%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.039605	$0.045800	$0.006195	15.64%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.129605	$0.108800	-$0.020805	-16.05%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.031385	$0.040036	$0.008651	27.56%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Small General Service Demand Time-of-Use				
Basic Service Charge	N/A	$30.00	N/A	N/A
Demand Charge, per kW	N/A	$5.49	N/A	N/A
Energy Charge (kWhs)	N/A	$0.016680	N/A	N/A
Base Power Supply Charge, Summer On-Peak all kWhs	N/A	$0.084570	N/A	N/A
Base Power Supply Charge, Summer Off-Peak all kWhs	N/A	$0.045800	N/A	N/A
Base Power Supply Charge, Winter On-Peak all kWhs	N/A	$0.083570	N/A	N/A
Base Power Supply Charge, Winter Off-Peak all kWhs	N/A	$0.040036	N/A	N/A
PPFAC[1]	N/A	$0.000000	N/A	N/A
Medium General Service[2]				
Basic Service Charge	$50.00	$100.00	$50.00	100.00%
Demand Charge, per kW	$12.81	$13.95	$1.14	8.90%
Energy Charge (kWhs)	$0.005470	$0.005500	$0.000030	0.55%
Base Power Supply Charge, all kWhs	$0.056603	$0.053290	-$0.003313	-5.85%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Medium General Service Time-of-Use[2]				
Basic Service Charge	$52.00	$100.00	$48.00	92.31%
Demand Charge, per kW	$12.81	$13.95	$1.14	8.90%
Energy Charge (kWhs)	$0.005470	$0.005500	$0.000030	0.55%
Base Power Supply Charge, Summer On-Peak all kWhs	$0.114886	$0.114886	$0.000000	0.00%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.039886	$0.033500	-$0.006386	-16.01%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.114886	$0.101047	-$0.013839	-12.05%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.026168	$0.031690	$0.005522	21.10%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%

UNS Electric, Inc.
Comparison of Present and Proposed Rates
Test Year Ended December 31, 2014

	Present Rate	Proposed Rate	Increase $	Increase %
Large General Service				
Basic Service Charge	$50.00	$300.00	$250.00	500.00%
Demand Charge, per kW	$12.81	$13.35	$0.54	4.22%
Energy Charge (kWhs)	$0.005470	$0.005470	$0.000000	0.00%
Base Power Supply Charge, all kWhs	$0.056603	$0.053290	-$0.003313	-5.85%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Large General Service Time-of-Use				
Basic Service Charge	$52.00	$300.00	$248.00	476.92%
Demand Charge, per kW	$12.81	$13.35	$0.54	4.22%
Energy Charge (kWhs)	$0.005470	$0.005470	$0.000000	0.00%
Base Power Supply Charge, Summer On-Peak all kWhs	$0.114886	$0.143771	$0.028885	25.14%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.039886	$0.038600	-$0.001286	-3.22%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.114886	$0.139880	$0.024994	21.76%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.026168	$0.034927	$0.008759	33.47%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Large Power Service[3]				
Basic Service Charge <69 kV	$1,200.00	$300.00	-$900.00	-75.00%
Basic Service Charge ≥69 kV	$1,200.00	$1,500.00	$300.00	25.00%
Demand Charge <69kV, per kW	$22.00	$13.35	-$8.65	-39.32%
Demand Charge ≥69kV, per kW	$17.00	$13.00	-$4.00	-23.53%
Energy Charge (kWhs) <69 kV	$0.000462	$0.005470	$0.005008	1083.98%
Energy Charge (kWhs) ≥69 kV	$0.000462	$0.000500	$0.000038	8.23%
Base Power Supply Charge, all kWhs <69 kV	$0.041880	$0.053290	$0.011410	27.24%
Base Power Supply Charge, all kWhs ≥69 kV	$0.041880	$0.049332	$0.007452	17.79%
PPFAC[1] <69kV	($0.002139)	$0.000000	$0.002139	100.00%
PPFAC[1] ≥69kV	($0.002139)	$0.000000	$0.002139	100.00%
Large Power Service Time-of-Use[3]				
Basic Service Charge <69 kV	$1,200.00	$300.00	-$900.00	-75.00%
Basic Service Charge ≥69 kV	$1,200.00	$1,500.00	$300.00	25.00%
Demand Charge <69kV, per kW	$22.00	$13.35	-$8.65	-39.32%
Demand Charge ≥69kV, per kW	$17.00	$13.00	-$4.00	-23.53%
Energy Charge (kWhs) <69 kV	$0.000462	$0.005470	$0.005008	1083.98%
Energy Charge (kWhs) ≥69 kV	$0.000462	$0.000500	$0.000038	8.23%
Base Power Supply Charge <69 kV				
Base Power Supply Charge, Summer On-Peak all kWhs	$0.123580	$0.143771	$0.020191	16.34%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.024716	$0.038600	$0.013884	56.17%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.093880	$0.139880	$0.046000	49.00%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.022105	$0.034927	$0.012822	58.00%
Base Power Supply Charge ≥69 kV				
Base Power Supply Charge, Summer On-Peak all kWhs	$0.123580	$0.125155	$0.001575	1.27%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.024716	$0.033410	$0.008694	35.18%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.093880	$0.092110	-$0.001770	-1.89%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.022105	$0.030410	$0.008305	37.57%
PPFAC[1] <69kV	($0.002139)	$0.000000	$0.002139	100.00%
PPFAC[1] ≥69kV	($0.002139)	$0.000000	$0.002139	100.00%
Large Power Service Mining (≥69kV)				
Basic Service Charge	$1,200.00	$1,500.00	$300.00	25.00%
Demand Charge, per kW	$17.00	$13.00	-$4.00	-23.53%
Energy Charge (kWhs)	$0.000462	$0.000500	$0.000038	8.23%
Base Power Supply Charge, all kWhs	$0.041880	$0.049332	$0.007452	17.79%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%

	Present Rate	Proposed Rate	Increase $	Increase %
Interruptible Power Service				
Basic Service Charge	$18.00	$75.00	$57.00	316.67%
Demand Charge, per kW	$5.00	$5.50	$0.50	10.00%
Energy Charge (kWhs)	$0.019408	$0.019800	$0.000392	2.02%
Base Power Supply Charge, all kWhs	$0.043760	$0.053090	$0.009330	21.32%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Lighting Dusk to Dawn				
New 30' Wood Pole (Class 6) - Overhead	$4.34	$4.68	$0.34	7.83%
New 30' Metal or Fiberglass - Overhead	$8.66	$9.35	$0.69	7.97%
Existing Wood Pole - Underground	$2.18	$2.35	$0.17	7.80%
New 30' Wood Pole (Class 6) - Underground	$6.52	$7.04	$0.52	7.98%
New 30' Metal or Fiberglass - Underground	$10.81	$11.67	$0.86	7.96%
Wattage, per Watt	$0.051681	$0.060516	$0.008835	17.10%
Lighting Base Power Supply Charge, per kWh	$0.010113	$0.014535	$0.004422	43.73%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
TOU - Medium General Service Schools (Formally TOU - Small General Service Schools)				
Basic Service Charge	$16.50	$100.00	$83.50	506.06%
Demand Charge, per kW	N/A	$13.95	N/A	N/A
Energy Charge 1st 400 kWh	$0.030176	$0.005500	-$0.024676	-81.77%
Energy Charge 401 -7,500 kWh	$0.043176	$0.005500	-$0.037676	-87.26%
Energy Charge >7,500 kWh	$0.076042	$0.005500	-$0.070542	-92.77%
Base Power Supply Charge, Summer On-Peak all kWhs	$0.137405	$0.120586	-$0.016819	-12.24%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.047405	$0.039200	-$0.008205	-17.31%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.137405	$0.106747	-$0.030658	-22.31%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.039185	$0.037390	-$0.001795	-4.58%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
TOU - Large General Service Schools				
Basic Service Charge	$52.00	$300.00	$248.00	476.92%
Demand Charge, per kW	$12.81	$13.35	$0.54	4.22%
Energy Charge (kWhs)	$0.005470	$0.005470	$0.000000	0.00%
Base Power Supply Charge, Summer On-Peak all kWhs	$0.120586	$0.148471	$0.027885	23.12%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.045586	$0.043300	-$0.002286	-5.01%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.120586	$0.144580	$0.023994	19.90%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.031868	$0.039627	$0.007759	24.35%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
RIDER R-5 ELECTRIC SERVICE SOLAR RIDER (BRIGHT ARIZONA COMMUNITY SOLAR™)				
Residential Electric, Rate R-01	$0.084510	$0.075090	-$0.009420	-11.15%
General Service, Rate SGS-10	$0.078241	$0.073290	-$0.004951	-6.33%
Medium General Service, R-MGS (Former LGS)	$0.076603	$0.073290	-$0.003313	-4.32%

[1] The Present Rate for the PPFAC is the Test Year average PPFAC, since the rate varies by month. The Proposed Rate is $0.00, since the PPFAC rate will be reset to zero for one month when the new base rates become effective. However, the PPFAC rate will change monthly in all subsequent months by an amount defined in the proposed PPFAC POA. The Company has proposed the PPFAC be a percentage based adjustment that will be recalculated monthly and reflected as a single percentage based adjustment applied to base fuel cost for each rate class (e.g. the percentage adjustment will be the same percentage value regardless of the rate class).

[2] For the new Medium General Service and Medium General Service Time-of-Use rates, the Present Rate column is populated with the currently existing rates for Large General Service and Large General Service Time-of-Use, respectively, since these two new Medium General Service classes will be comparable to the former Large General Service classes.

UNS Electric, Inc.
Comparison of Present and Proposed Rates
Test Year Ended December 31, 2014

Present Rate	Proposed Rate	Increase	
		$	%

[3] The proposed Large Power Service rate classes will be restricted to customers with ≥69kV service. The Proposed Rate column for <69kV service is populated with the Proposed Rates from the corresponding Large General Service rate classes.

Exhibit CAJ-R-4

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill
		0-400	401-1,000	1,000+	$10.00	$0.019300	$0.034350	$0.038499	$0.001140	$0.064510	-$0.002139	
Xsmall	111	111	0	0	$10.00	$2.14	$0.00	$0.00	$0.13	$7.16	-$0.24	$19.19
Small	330	330	0	0	$10.00	$6.37	$0.00	$0.00	$0.38	$21.29	-$0.71	$37.33
Medium	664	400	264	0	$10.00	$7.72	$9.07	$0.00	$0.76	$42.83	-$1.42	$68.96
Large	1,144	400	600	144	$10.00	$7.72	$20.61	$5.54	$1.30	$73.80	-$2.45	$116.53
Xlarge	2,162	400	600	1,162	$10.00	$7.72	$20.61	$44.74	$2.46	$139.47	-$4.63	$220.37
Mean	830	400	430	0	$10.00	$7.72	$14.75	$0.00	$0.95	$53.51	-$1.77	$85.16
Sum	983	400	583	0	$10.00	$7.72	$20.04	$0.00	$1.12	$63.43	-$2.10	$100.20
Win	669	400	269	0	$10.00	$7.72	$9.25	$0.00	$0.76	$43.18	-$1.43	$69.48
Annual												$1,018.12

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		0-400	401-1,000	1,000+	$15.00	$0.032258	$0.042258	$0.060258	$0.000000	$0.055090	0.000%			
Xsmall	111	111	0	0	$15.00	$3.58	$0.00	$0.00	$0.00	$6.12	$0.00	$24.70	$5.51	28.7%
Small	330	330	0	0	$15.00	$10.65	$0.00	$0.00	$0.00	$18.18	$0.00	$43.83	$6.49	17.4%
Medium	664	400	264	0	$15.00	$12.90	$11.16	$0.00	$0.00	$36.58	$0.00	$75.64	$6.68	9.7%
Large	1,144	400	600	144	$15.00	$12.90	$25.35	$8.68	$0.00	$63.02	$0.00	$124.96	$8.43	7.2%
Xlarge	2,162	400	600	1,162	$15.00	$12.90	$25.35	$70.02	$0.00	$119.11	$0.00	$242.39	$22.02	10.0%
Mean	830	400	430	0	$15.00	$12.90	$18.15	$0.00	$0.00	$45.70	$0.00	$91.75	$6.59	7.7%
Sum	983	400	583	0	$15.00	$12.90	$24.65	$0.00	$0.00	$54.17	$0.00	$106.72	$6.52	6.5%
Win	669	400	269	0	$15.00	$12.90	$11.38	$0.00	$0.00	$36.88	$0.00	$76.17	$6.69	9.6%
Annual												$1,097.35	$79.24	7.8%

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND

WINTER

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill
								0-400 kWh	401-1,000 kWh	1,000+ kWh				
				0-400	401-1,000	1,000+	$15.00	$0.032258	$0.042258	$0.060258	$0.000000	$0.055090	$0.000000	
Xsm	19%	0.7	100	100	0	0	$15.00	$3.23	$0.00	$0.00	$0.00	$5.51	$0.00	$23.74
Small	24%	1.7	294	294	0	0	$15.00	$9.48	$0.00	$0.00	$0.00	$16.20	$0.00	$40.68
Medium	28%	2.8	560	400	160	0	$15.00	$12.90	$6.76	$0.00	$0.00	$30.85	$0.00	$65.51
Large	31%	4.1	914	400	514	0	$15.00	$12.90	$21.72	$0.00	$0.00	$50.35	$0.00	$99.97
XLg	35%	6.5	1,653	400	600	653	$15.00	$12.90	$25.35	$39.35	$0.00	$91.06	$0.00	$183.67
AnnAvg	30%	3.8	830	400	430	0	$15.00	$12.90	$18.15	$0.00	$0.00	$45.70	$0.00	$91.75
WinAvg	29%	3.2	669	400	269	0	$15.00	$12.90	$11.38	$0.00	$0.00	$36.88	$0.00	$76.17

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
							All kW	All kWh							
				On-Peak	Off-Peak	$15.00	$5.15	$0.01676	$0.000000						
Winter				0.26	0.74					$0.082800	$0.038610	0.000%			
Summer										$0.102251	$0.042830				
Xsm	19%	0.7	100	26	74	$15.00	$3.61	$1.68	$0.00	$2.15	$2.86	$0.00	$25.30	$1.56	6.59%
Small	24%	1.7	294	76	218	$15.00	$8.76	$4.93	$0.00	$6.29	$8.42	$0.00	$43.40	$2.72	6.68%
Medium	28%	2.8	560	145	415	$15.00	$14.42	$9.39	$0.00	$12.01	$16.02	$0.00	$66.84	$1.33	2.02%
Large	31%	4.1	914	237	677	$15.00	$21.12	$15.32	$0.00	$19.62	$26.14	$0.00	$97.20	-$2.77	-2.77%
XLg	35%	6.5	1,653	429	1,224	$15.00	$33.48	$27.70	$0.00	$35.52	$47.26	$0.00	$158.96	-$24.71	-13.45%
AnnAvg	30%	3.8	830	215	614	$15.00	$19.57	$13.90	$0.00	$17.80	$23.71	$0.00	$89.98	-$1.77	-1.93%
WinAvg	29%	3.2	669	174	496	$15.00	$16.48	$11.22	$0.00	$14.41	$19.15	$0.00	$76.26	$0.09	0.12%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SUMMER

RESIDENTIAL SERVICE DEMAND

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh				
							$15.00	$0.032258	$0.042258	$0.060258	$0.000000	$0.055090	$0.000000	
Xsm	20%	0.8	117	117	0	0	$15.00	$3.77	$0.00	$0.00	$0.00	$6.45	$0.00	$25.22
Small	25%	2.1	386	386	0	0	$15.00	$12.45	$0.00	$0.00	$0.00	$21.26	$0.00	$48.71
Medium	30%	3.7	813	400	413	0	$15.00	$12.90	$17.45	$0.00	$0.00	$44.79	$0.00	$90.15
Large	34%	5.7	1,395	400	600	395	$15.00	$12.90	$25.35	$23.80	$0.00	$76.85	$0.00	$153.91
XLg	38%	9.0	2,471	400	600	1,471	$15.00	$12.90	$25.35	$88.64	$0.00	$136.13	$0.00	$278.03
AnnAvg	30%	3.8	830	400	430	0	$15.00	$12.90	$18.15	$0.00	$0.00	$45.70	$0.00	$91.75
SumAvg	31%	4.3	983	400	583	0	$15.00	$12.90	$24.65	$0.00	$0.00	$54.17	$0.00	$106.72

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak		All kW	All kWh							
						$15.00	$5.15	$0.01676	$0.000000						
Winter										$0.082800	$0.038610				
Summer				0.24	0.76					$0.102251	$0.042830	0.000%			
Xsm	20%	0.8	117	28	89	$15.00	$4.12	$1.96	$0.00	$2.86	$3.81	$0.00	$27.75	$2.53	10.01%
Small	25%	2.1	386	93	293	$15.00	$10.82	$6.47	$0.00	$9.51	$12.55	$0.00	$54.35	$5.64	11.57%
Medium	30%	3.7	813	196	617	$15.00	$19.06	$13.63	$0.00	$20.04	$26.43	$0.00	$94.16	$4.01	4.45%
Large	34%	5.7	1,395	336	1,059	$15.00	$29.36	$23.38	$0.00	$34.36	$45.36	$0.00	$147.46	-$6.45	-4.19%
XLg	38%	9.0	2,471	595	1,876	$15.00	$46.35	$41.41	$0.00	$60.84	$80.35	$0.00	$243.95	-$34.08	-12.26%
AnnAvg	30%	3.8	830	200	630	$15.00	$19.57	$13.90	$0.00	$20.45	$26.98	$0.00	$95.90	$4.15	4.52%
SumAvg	31%	4.3	983	237	747	$15.00	$22.15	$16.48	$0.00	$24.23	$31.99	$0.00	$109.85	$3.13	2.93%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE CARES

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Bill	Discounts
		1-400	401+	$4.90	$0.018973	$0.035400	$0.001140	$0.061700	-$0.002139		
Xsmall	220	220	0	$4.90	$4.17	$0.00	$0.25	$13.57	-$0.47	$15.69	30.00%
Small	360	360	0	$4.90	$6.83	$0.00	$0.41	$22.21	-$0.77	$26.86	20.00%
Medium	607	400	207	$4.90	$7.59	$7.33	$0.69	$37.45	-$1.30	$50.99	10.00%
Large	990	400	590	$4.90	$7.59	$20.89	$1.13	$61.08	-$2.12	$84.12	10.00%
Xlarge	1,843	400	1,443	$4.90	$7.59	$51.08	$2.10	$113.71	-$3.94	$167.44	$8.00
Mean	753	400	353	$4.90	$7.59	$12.49	$0.86	$46.45	-$1.61	$63.61	10.00%
Sum	867	400	467	$4.90	$7.59	$16.53	$0.99	$53.49	-$1.85	$73.49	10.00%
Win	638	400	238	$4.90	$7.59	$8.43	$0.73	$39.37	-$1.37	$53.69	10.00%
Annual										$763.08	

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change	Discounts
		1-400	401+	$9.00	$0.030800	$0.050800	$0.000000	$0.050260	0.000%				
Xsmall	220	220	0	$9.00	$6.78	$0.00	$0.00	$11.06	$0.00	$18.79	$3.10	19.75%	30.00%
Small	360	360	0	$9.00	$11.09	$0.00	$0.00	$18.09	$0.00	$30.54	$3.68	13.72%	20.00%
Medium	607	400	207	$9.00	$12.32	$10.52	$0.00	$30.51	$0.00	$56.12	$5.13	10.05%	10.00%
Large	990	400	590	$9.00	$12.32	$29.97	$0.00	$49.76	$0.00	$90.95	$6.82	8.11%	10.00%
Xlarge	1,843	400	1,443	$9.00	$12.32	$73.30	$0.00	$92.63	$0.00	$179.25	$11.81	7.05%	$8.00
Mean	753	400	353	$9.00	$12.32	$17.93	$0.00	$37.84	$0.00	$69.38	$5.77	9.07%	10.00%
Sum	867	400	467	$9.00	$12.32	$23.72	$0.00	$43.57	$0.00	$79.75	$6.26	8.52%	10.00%
Win	638	400	238	$9.00	$12.32	$12.09	$0.00	$32.07	$0.00	$58.93	$5.24	9.76%	10.00%
Annual										$832.09	$69.01	9.04%	

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE CARES MEDICAL

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Revenue	Discounts
		1-400	401+	$4.90	$0.018973	$0.035400	$0.001140	$0.061700	-$0.002139		
Xsmall	365	365	0	$4.90	$6.93	$0.00	$0.42	$22.52	-$0.78	$23.79	30.00%
Small	564	400	164	$4.90	$7.59	$5.81	$0.64	$34.80	-$1.21	$36.77	30.00%
Medium	878	400	478	$4.90	$7.59	$16.92	$1.00	$54.17	-$1.88	$66.16	20.00%
Large	1,340	400	940	$4.90	$7.59	$33.28	$1.53	$82.68	-$2.87	$114.40	10.00%
Xlarge	2,304	400	1,904	$4.90	$7.59	$67.40	$2.63	$142.16	-$4.93	$211.75	$8.00
Mean	1,034	400	634	$4.90	$7.59	$22.43	$1.18	$63.78	-$2.21	$78.13	20.00%
sum	1,199	400	799	$4.90	$7.59	$28.28	$1.37	$73.97	-$2.56	$90.84	20.00%
win	871	400	471	$4.90	$7.59	$16.68	$0.99	$53.75	-$1.86	$65.64	20.00%
Annual										$938.88	

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Revenue	$ Change	% Change	Discounts
		1-400	401+	$9.00	$0.030800	$0.050800	$0.000000	$0.050260	0.000%				
Xsmall	365	365	0	$9.00	$11.24	$0.00	$0.00	$18.34	$0.00	$27.01	$3.22	13.5%	30.00%
Small	564	400	164	$9.00	$12.32	$8.33	$0.00	$28.35	$0.00	$40.60	$3.83	10.4%	30.00%
Medium	878	400	478	$9.00	$12.32	$24.28	$0.00	$44.13	$0.00	$71.78	$5.62	8.5%	20.00%
Large	1,340	400	940	$9.00	$12.32	$47.75	$0.00	$67.35	$0.00	$136.32	$21.92	19.2%	10.00%
Xlarge	2,304	400	1,904	$9.00	$12.32	$96.72	$0.00	$115.80	$0.00	$225.84	$14.09	6.7%	$8.00
Mean	1,034	400	634	$9.00	$12.32	$32.19	$0.00	$51.95	$0.00	$84.37	$6.24	8.0%	20.00%
sum	1,199	400	799	$9.00	$12.32	$40.58	$0.00	$60.25	$0.00	$97.72	$6.88	7.6%	20.00%
win	871	400	471	$9.00	$12.32	$23.93	$0.00	$43.78	$0.00	$71.22	$5.58	8.5%	20.00%
Annual										$1,013.66	$74.78	8.0%	

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND - CARES

WINTER

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill	Discounts
								0-400 kWh	401-1,000 kWh	1,000+ kWh					
				0-400	401-1,000	1,000+	$9.00	$0.030800	$0.050800	$0.050800	$0.000000	$0.050260	$0.000000		
Xsm	22%	1.2	198	198	0	0	$9.00	$6.10	$0.00	$0.00	$0.00	$9.95	$0.00	$17.53	30.00%
Small	25%	1.8	324	324	0	0	$9.00	$9.98	$0.00	$0.00	$0.00	$16.28	$0.00	$28.21	20.00%
Medium	27%	2.7	525	400	125	0	$9.00	$12.32	$6.35	$0.00	$0.00	$26.39	$0.00	$48.65	10.00%
Large	30%	3.8	831	400	431	0	$9.00	$12.32	$21.89	$0.00	$0.00	$41.77	$0.00	$76.49	10.00%
XLg	34%	6.0	1,496	400	600	496	$9.00	$12.32	$30.48	$25.20	$0.00	$75.19	$0.00	$144.19	$8.00
AnnAvg	30%	3.9	867	400	467	0	$9.00	$12.32	$23.72	$0.00	$0.00	$43.57	$0.00	$79.75	10.00%
WinAvg	28%	3.1	638	400	238	0	$9.00	$12.32	$12.09	$0.00	$0.00	$32.07	$0.00	$58.94	10.00%

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
				On-Peak	Off-Peak		All kW	All kWh								
						15.00	5.15	$0.01676	$0.000000							
Winter				0.26	0.74					$0.082800	$0.038610	0.000%				
Summer										$0.102251	$0.042830					
Xsm	22%	1.2	198	51	147	$15.00	$6.18	$3.32	$0.00	$4.22	$5.68	$0.00	$28.21	$10.68	60.9%	18.00%
Small	25%	1.8	324	84	240	$15.00	$9.27	$5.43	$0.00	$6.96	$9.27	$0.00	$37.66	$9.45	33.5%	18.00%
Medium	27%	2.7	525	136	389	$15.00	$13.91	$8.80	$0.00	$11.26	$15.02	$0.00	$52.47	$3.82	7.9%	18.00%
Large	30%	3.8	831	216	615	$15.00	$19.57	$13.93	$0.00	$17.88	$23.75	$0.00	$73.91	-$2.58	-3.4%	18.00%
XLg	34%	6.0	1,496	388	1,108	$15.00	$30.90	$25.07	$0.00	$32.13	$42.78	$0.00	$129.88	-$14.31	-9.9%	$16.00
AnnAvg	30%	3.9	867	225	642	$15.00	$20.09	$14.53	$0.00	$18.63	$24.79	$0.00	$76.29	-$3.46	-4.3%	18.00%
WinAvg	28%	3.1	638	166	472	$15.00	$15.97	$10.69	$0.00	$13.74	$18.22	$0.00	$60.37	$1.43	2.4%	18.00%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND - CARES

SUMMER

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh					
							$9.00	$0.030800	$0.050800	$0.050800	$0.000000	$0.050260	$0.000000		
Xsm	23%	1.4	243	243	0	0	$9.00	$7.48	$0.00	$0.00	$0.00	$12.21	$0.00	$20.09	30.00%
Small	26%	2.2	413	400	13	0	$9.00	$12.32	$0.66	$0.00	$0.00	$20.76	$0.00	$34.19	20.00%
Medium	29%	3.4	709	400	309	0	$9.00	$12.32	$15.70	$0.00	$0.00	$35.63	$0.00	$65.38	10.00%
Large	32%	4.9	1,161	400	600	161	$9.00	$12.32	$30.48	$8.18	$0.00	$58.35	$0.00	$110.33	$8.00
XLg	37%	7.8	2,078	400	600	1,078	$9.00	$12.32	$30.48	$54.76	$0.00	$104.44	$0.00	$203.00	$8.00
AnnAvg	30%	3.9	867	400	467	0	$9.00	$12.32	$23.72	$0.00	$0.00	$43.57	$0.00	$79.75	10.00%
SumAvg	30%	3.9	863	400	463	0	$9.00	$12.32	$23.54	$0.00	$0.00	$43.39	$0.00	$79.43	10.00%

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
				On-Peak	Off-Peak		All kW	All kWh								
						$15.00	$5.15	$0.01676	$0.000000							
Winter										$0.082800	$0.038610					
Summer				0.24	0.76					$0.102251	$0.042830	0.000%				
Xsm	23%	1.4	243	58	185	$15.00	$7.21	$4.07	$0.00	$5.93	$7.92	$0.00	$32.91	$12.82	63.8%	18.00%
Small	26%	2.2	413	99	314	$15.00	$11.33	$6.92	$0.00	$10.12	$13.45	$0.00	$46.59	$12.40	36.3%	18.00%
Medium	29%	3.4	709	171	538	$15.00	$17.51	$11.88	$0.00	$17.48	$23.04	$0.00	$69.63	$4.25	6.5%	18.00%
Large	32%	4.9	1,161	279	882	$15.00	$25.24	$19.46	$0.00	$28.53	$37.78	$0.00	$110.01	-$0.32	-0.3%	$16.00
XLg	37%	7.8	2,078	500	1,578	$15.00	$40.17	$34.83	$0.00	$51.13	$67.59	$0.00	$192.72	-$10.28	-5.1%	$16.00
AnnAvg	30%	3.9	867	209	658	$15.00	$20.09	$14.53	$0.00	$21.37	$28.18	$0.00	$81.32	$1.57	2.0%	18.00%
SumAvg	30%	3.9	863	208	656	$15.00	$20.09	$14.47	$0.00	$21.27	$28.10	$0.00	$81.12	$1.69	2.1%	18.00%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

Exhibit CAJ-R-4

Schedule H-4

WINTER

RESIDENTIAL SERVICE DEMAND - CARES MEDICAL

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh					
							$9.00	$0.030800	$0.050800	$0.050800	$0.000000	$0.050260	$0.000000		
Xsm	24%	1.8	323	323	0	0	$9.00	$9.95	$0.00	$0.00	$0.00	$16.23	$0.00	$24.62	30.00%
Small	27%	2.5	495	400	95	0	$9.00	$12.32	$4.83	$0.00	$0.00	$24.88	$0.00	$35.72	30.00%
Medium	29%	3.6	763	400	363	0	$9.00	$12.32	$18.44	$0.00	$0.00	$38.35	$0.00	$62.49	20.00%
Large	32%	4.8	1,115	400	600	115	$9.00	$12.32	$30.48	$5.84	$0.00	$56.04	$0.00	$90.95	20.00%
XLg	36%	7.2	1,887	400	600	887	$9.00	$12.32	$30.48	$45.06	$0.00	$94.84	$0.00	$172.53	10.00%
AnnAvg	32%	5.1	1,199	400	600	199	$9.00	$12.32	$30.48	$10.10	$0.00	$60.25	$0.00	$97.72	20.00%
WinAvg	30%	4.0	871	400	471	0	$9.00	$12.32	$23.93	$0.00	$0.00	$43.78	$0.00	$71.23	20.00%

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
				On-Peak	Off-Peak		All kW	All kWh								
						15.00	5.15	$0.01676	$0.000000							
Winter				0.26	0.74					$0.082800	$0.038610	0.000%				
Summer										$0.102251	$0.042830					
Xsm	24%	1.8	323	84	239	$15.00	$9.27	$5.41	$0.00	$6.96	$9.23	$0.00	$34.86	$10.24	41.6%	24.00%
Small	27%	2.5	495	128	367	$15.00	$12.88	$8.30	$0.00	$10.60	$14.17	$0.00	$46.32	$10.60	29.7%	24.00%
Medium	29%	3.6	763	198	565	$15.00	$18.54	$12.79	$0.00	$16.39	$21.81	$0.00	$64.24	$1.75	2.8%	24.00%
Large	32%	4.8	1,115	289	826	$15.00	$24.72	$18.69	$0.00	$23.93	$31.89	$0.00	$86.81	-$4.14	-4.6%	24.00%
XLg	36%	7.2	1,887	490	1,397	$15.00	$37.08	$31.63	$0.00	$40.57	$53.94	$0.00	$135.45	-$37.08	-21.5%	24.00%
AnnAvg	32%	5.1	1,199	311	888	$15.00	$26.27	$20.09	$0.00	$25.75	$34.29	$0.00	$92.26	-$5.46	-5.6%	24.00%
WinAvg	30%	4.0	871	226	645	$15.00	$20.60	$14.60	$0.00	$18.71	$24.90	$0.00	$71.30	$0.07	0.1%	24.00%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND - CARES MEDICAL

SUMMER

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh					
							$9.00	$0.030800	$0.050800	$0.050800	$0.000000	$0.050260	$0.000000		
Xsm	26%	2.2	414	400	14	0	$9.00	$12.32	$0.71	$0.00	$0.00	$20.81	$0.00	$29.99	30.00%
Small	29%	3.2	663	400	263	0	$9.00	$12.32	$13.34	$0.00	$0.00	$33.30	$0.00	$54.36	20.00%
Medium	31%	4.5	1,035	400	600	35	$9.00	$12.32	$30.48	$1.78	$0.00	$52.02	$0.00	$84.48	20.00%
Large	34%	6.3	1,572	400	600	572	$9.00	$12.32	$30.48	$29.03	$0.00	$78.98	$0.00	$143.83	10.00%
XLg	38%	9.3	2,601	400	600	1,601	$9.00	$12.32	$30.48	$81.33	$0.00	$130.73	$0.00	$255.86	$8.00
AnnAvg	32%	5.1	1,199	400	600	199	$9.00	$12.32	$30.48	$10.10	$0.00	$60.25	$0.00	$97.72	20.00%
SumAvg	32%	5.0	1,194	400	600	194	$9.00	$12.32	$30.48	$9.84	$0.00	$60.00	$0.00	$97.32	20.00%

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
				On-Peak	Off-Peak			All kW	All kWh								
							$15.00	$5.15	$0.01676	$0.000000							
Winter											$0.082800	$0.038610					
Summer				0.24	0.76						$0.102251	$0.042830	0.000%				
Xsm	26%	2.2	414	100	314		$15.00	$11.33	$6.94	$0.00	$10.23	$13.45	$0.00	$43.28	$13.29	44.3%	24.00%
Small	29%	3.2	663	159	503		$15.00	$16.48	$11.10	$0.00	$16.26	$21.54	$0.00	$61.09	$6.73	12.4%	24.00%
Medium	31%	4.5	1,035	249	786		$15.00	$23.18	$17.35	$0.00	$25.46	$33.66	$0.00	$87.13	$2.65	3.1%	24.00%
Large	34%	6.3	1,572	378	1,193		$15.00	$32.45	$26.34	$0.00	$38.65	$51.10	$0.00	$124.29	-$19.54	-13.6%	24.00%
XLg	38%	9.3	2,601	626	1,975		$15.00	$47.90	$43.59	$0.00	$64.01	$84.59	$0.00	$239.09	-$16.77	-6.6%	$16.00
AnnAvg	32%	5.1	1,199	288	910		$15.00	$26.27	$20.09	$0.00	$29.45	$38.98	$0.00	$98.64	$0.92	0.9%	24.00%
SumAvg	32%	5.0	1,194	287	907		$15.00	$25.75	$20.01	$0.00	$29.35	$38.85	$0.00	$98.01	$0.69	0.7%	24.00%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+							
	Winter	0.24	0.76				$11.50	$0.030350	$0.001140	$0.129605	$0.031385	-$0.002139	
	Summer									$0.129605	$0.039605		
Xsm	150	36	114	150	0	0	$11.50	$4.55	$0.17	$4.67	$3.58	-$0.32	$24.15
Small	286	69	217	286	0	0	$11.50	$8.68	$0.33	$8.90	$6.82	-$0.61	$35.62
Medium	641	154	487	400	241	0	$11.50	$19.45	$0.73	$19.94	$15.29	-$1.37	$65.54
Large	1,043	250	793	400	600	43	$11.50	$31.66	$1.19	$32.44	$24.88	-$2.23	$99.44
XLg	1,810	434	1,376	400	600	810	$11.50	$54.93	$2.06	$56.30	$43.17	-$3.87	$164.09
AnnAvg	1,008	242	766	400	600	8	$11.50	$30.59	$1.15	$31.36	$24.05	-$2.16	$96.49
Avg Win	801	192	608	400	401	0	$11.50	$24.30	$0.91	$24.90	$19.10	-$1.71	$79.00

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+							
	Winter						$15.00	$0.036900	$0.036900	$0.036900	$0.000000	$0.091550	$0.038610	0.000%			
	Summer											$0.111001	$0.042830			$ Change	% Change
Xsm	150	36	114	150	0	0	$15.00	$5.54	$0.00	$0.00	$0.00	$3.30	$4.40	$0.00	$28.24	$4.09	16.94%
Small	286	69	217	286	0	0	$15.00	$10.55	$0.00	$0.00	$0.00	$6.28	$8.39	$0.00	$40.22	$4.60	12.91%
Medium	641	154	487	400	241	0	$15.00	$14.76	$8.89	$0.00	$0.00	$14.08	$18.81	$0.00	$71.54	$6.00	9.15%
Large	1,043	250	793	400	600	43	$15.00	$14.76	$22.14	$1.59	$0.00	$22.92	$30.61	$0.00	$107.02	$7.58	7.62%
XLg	1,810	434	1,376	400	600	810	$15.00	$14.76	$22.14	$29.89	$0.00	$39.77	$53.11	$0.00	$174.67	$10.58	6.45%
AnnAvg	1,008	242	766	400	600	8	$15.00	$14.76	$22.14	$0.30	$0.00	$22.15	$29.58	$0.00	$103.93	$7.44	7.71%
Avg Win	801	192	608	400	401	0	$15.00	$14.76	$14.78	$0.00	$0.00	$17.59	$23.49	$0.00	$85.62	$6.62	8.38%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+							
	Winter						$11.50	$0.030350	$0.001140	$0.129605	$0.031385	-$0.002139	
	Summer	0.23	0.77							$0.129605	$0.039605		
Xsm	261	60	201	261	0	0	$11.50	$7.92	$0.30	$7.78	$7.96	-$0.56	$34.90
Small	525	121	404	400	125	0	$11.50	$15.93	$0.60	$15.65	$16.01	-$1.12	$58.57
Medium	983	226	757	400	583	0	$11.50	$29.83	$1.12	$29.30	$29.98	-$2.10	$99.63
Large	1,611	371	1,240	400	600	611	$11.50	$48.89	$1.84	$48.02	$49.13	-$3.45	$155.93
XLg	2,681	617	2,064	400	600	1,681	$11.50	$81.37	$3.06	$79.92	$81.76	-$5.74	$251.87
AnnAvg	1,008	232	776	400	600	8	$11.50	$30.59	$1.15	$30.05	$30.74	-$2.16	$101.87
Avg Sum	1,195	275	920	400	600	195	$11.50	$36.26	$1.36	$35.61	$36.43	-$2.56	$118.60

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+							
	Winter						$15.00	$0.036900	$0.036900	$0.036900	$0.000000	$0.091550	$0.038610				
	Summer											$0.111001	$0.042830	0.000%		$ Change	% Change
Xsm	261	60	201	261	0	0	$15.00	$9.63	$0.00	$0.00	$0.00	$6.66	$8.61	$0.00	$39.90	$5.00	14.32%
Small	525	121	404	400	125	0	$15.00	$14.76	$4.61	$0.00	$0.00	$13.40	$17.31	$0.00	$65.08	$6.51	11.12%
Medium	983	226	757	400	583	0	$15.00	$14.76	$21.51	$0.00	$0.00	$25.10	$32.42	$0.00	$108.79	$9.16	9.20%
Large	1,611	371	1,240	400	600	611	$15.00	$14.76	$22.14	$22.55	$0.00	$41.13	$53.13	$0.00	$168.71	$12.78	8.19%
XLg	2,681	617	2,064	400	600	1,681	$15.00	$14.76	$22.14	$62.03	$0.00	$68.45	$88.42	$0.00	$270.80	$18.93	7.51%
AnnAvg	1,008	232	776	400	600	8	$15.00	$14.76	$22.14	$0.30	$0.00	$25.74	$33.25	$0.00	$111.19	$9.32	9.15%
Avg Sum	1,195	275	920	400	600	195	$15.00	$14.76	$22.14	$7.19	$0.00	$30.50	$39.40	$0.00	$128.99	$10.39	8.76%

	Net Bill	$ Change	% Change
Current Annual	$1,185.62		
Proposed Annual	$1,287.66	$102.04	8.61%

WINTER

RESIDENTIAL SERVICE RATE TIME OF USE DEMAND

BILL IMPACTS PROPOSED RES-TOU RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
	Winter	0.24	0.76				$15.00	$0.036900	$0.036900	$0.036900	$0.000000	$0.091550	$0.038610	0.000%	
	Summer											$0.111001	$0.042830		
Xsm	150	36	114	150	0	0	$15.00	$5.54	$0.00	$0.00	$0.00	$3.30	$4.40	$0.00	$28.24
Small	286	69	217	286	0	0	$15.00	$10.55	$0.00	$0.00	$0.00	$6.28	$8.39	$0.00	$40.22
Medium	641	154	487	400	241	0	$15.00	$14.76	$8.89	$0.00	$0.00	$14.08	$18.81	$0.00	$71.54
Large	1,043	250	793	400	600	43	$15.00	$14.76	$22.14	$1.59	$0.00	$22.92	$30.61	$0.00	$107.02
XLg	1,810	434	1,376	400	600	810	$15.00	$14.76	$22.14	$29.89	$0.00	$39.77	$53.11	$0.00	$174.67
AnnAvg	1,008	242	766	400	600	8	$15.00	$14.76	$22.14	$0.30	$0.00	$22.15	$29.58	$0.00	$103.93
WinAvg	801	192	608	400	401	0	$15.00	$14.76	$14.78	$0.00	$0.00	$17.59	$23.49	$0.00	$85.62

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak					All kW	All kWh							
Winter		0.24	0.76				$15.00	$5.15	$0.01676	$0.000000	$0.082800	$0.038610	0.000%			
Summer											$0.102251	$0.042830				
Xsm	150	36	114	21%	1.0		$15.00	$5.15	$2.51	$0.00	$2.98	$4.40	$0.00	$30.04	$1.80	6.37%
Small	286	69	217	24%	1.6		$15.00	$8.24	$4.79	$0.00	$5.68	$8.39	$0.00	$42.10	$1.88	4.67%
Medium	641	154	487	28%	3.1		$15.00	$15.97	$10.74	$0.00	$12.74	$18.81	$0.00	$73.26	$1.72	2.40%
Large	1,043	250	793	31%	4.5		$15.00	$23.18	$17.48	$0.00	$20.73	$30.61	$0.00	$107.00	-$0.02	-0.02%
XLg	1,810	434	1,376	35%	7.0		$15.00	$36.05	$30.34	$0.00	$35.97	$53.11	$0.00	$170.47	-$4.20	-2.40%
AnnAvg	1,008	242	766	31%	4.4		$15.00	$22.66	$16.90	$0.00	$20.03	$29.58	$0.00	$104.17	$0.24	0.23%
WinAvg	801	192	608	30%	3.7		$15.00	$19.06	$13.42	$0.00	$15.91	$23.49	$0.00	$86.88	$1.26	1.47%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE DEMAND

SUMMER

BILL IMPACTS PROPOSED RES-TOU RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
	Winter						$15.00	$0.036900	$0.036900	$0.036900	$0.000000	$0.091550	$0.038610		
	Summer	0.23	0.77									$0.111001	$0.042830	0.000%	
Xsm	261	60	201	261	0	0	$15.00	$9.63	$0.00	$0.00	$0.00	$6.66	$8.61	$0.00	$39.90
Small	525	121	404	400	125	0	$15.00	$14.76	$4.61	$0.00	$0.00	$13.40	$17.31	$0.00	$65.08
Medium	983	226	757	400	583	0	$15.00	$14.76	$21.51	$0.00	$0.00	$25.10	$32.42	$0.00	$108.79
Large	1,611	371	1,240	400	600	611	$15.00	$14.76	$22.14	$22.55	$0.00	$41.13	$53.13	$0.00	$168.71
XLg	2,681	617	2,064	400	600	1,681	$15.00	$14.76	$22.14	$62.03	$0.00	$68.45	$88.42	$0.00	$270.80
AnnAvg	1,008	232	776	400	600	8	$15.00	$14.76	$22.14	$0.30	$0.00	$25.74	$33.25	$0.00	$111.19
SumAvg	1,195	275	920	400	600	195	$15.00	$14.76	$22.14	$7.19	$0.00	$30.50	$39.40	$0.00	$128.99

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak					All kW	All kWh							
							$15.00	$5.15	$0.01676	$0.000000						
Winter											$0.082800	$0.038610				
Summer		0.23	0.77								$0.102251	$0.042830	0.000%			
Xsm	261	60	201	23%	1.5		$15.00	$7.73	$4.37	$0.00	$6.14	$8.61	$0.00	$41.85	$1.95	4.89%
Small	525	121	404	27%	2.7		$15.00	$13.91	$8.80	$0.00	$12.37	$17.30	$0.00	$67.38	$2.30	3.53%
Medium	983	226	757	31%	4.3		$15.00	$22.15	$16.48	$0.00	$23.11	$32.42	$0.00	$109.16	$0.37	0.34%
Large	1,611	371	1,240	35%	6.4		$15.00	$32.96	$27.00	$0.00	$37.94	$53.11	$0.00	$166.01	-$2.70	-1.60%
XLg	2,681	617	2,064	39%	9.5		$15.00	$48.93	$44.93	$0.00	$63.09	$88.40	$0.00	$260.35	-$10.45	-3.86%
AnnAvg	1,008	232	776	31%	4.4		$15.00	$22.66	$16.90	$0.00	$23.72	$33.24	$0.00	$111.52	$0.33	0.30%
SumAvg	1,195	275	920	32%	5.1		$15.00	$26.27	$20.02	$0.00	$28.12	$39.40	$0.00	$128.81	-$0.18	-0.14%

Notes: 1. This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE - SUPER PEAK

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
	Winter	0.1	0.9				$11.50	$0.025000	$0.035000	$0.035000	$0.001140	$0.150000	$0.038700	-$0.002139	
	Summer											$0.170000	$0.039700		
Xsm	150	15	135	150	0	0	$11.50	$3.75	$0.00	$0.00	$0.17	$2.25	$5.22	-$0.32	$22.57
Small	286	29	257	286	0	0	$11.50	$7.15	$0.00	$0.00	$0.33	$4.29	$9.96	-$0.61	$32.62
Medium	641	64	577	400	241	0	$11.50	$10.00	$8.44	$0.00	$0.73	$9.62	$22.33	-$1.37	$61.25
Large	1,043	104	939	400	600	43	$11.50	$10.00	$21.00	$1.51	$1.19	$15.65	$36.33	-$2.23	$94.95
XLg	1,810	181	1,629	400	600	810	$11.50	$10.00	$21.00	$28.35	$2.06	$27.15	$63.04	-$3.87	$159.23
AnnAvg	1,008	101	907	400	600	8	$11.50	$10.00	$21.00	$0.28	$1.15	$15.12	$35.11	-$2.16	$92.00
Avg Win	801	80	721	400	401	0	$11.50	$10.00	$14.02	$0.00	$0.91	$12.01	$27.89	-$1.71	$74.62

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+							
	Winter						$15.00	$0.032258	$0.035500	$0.035500	$0.000000	$0.159790	$0.040810	0.000%			
	Summer											$0.159790	$0.040810				
Xsm	150	15	135	150	0	0	$15.00	$4.84	$0.00	$0.00	$0.00	$2.40	$5.51	$0.00	$27.75	$5.18	22.95%
Small	286	29	257	286	0	0	$15.00	$9.23	$0.00	$0.00	$0.00	$4.57	$10.50	$0.00	$39.30	$6.68	20.48%
Medium	641	64	577	400	241	0	$15.00	$12.90	$8.56	$0.00	$0.00	$10.24	$23.54	$0.00	$70.24	$8.99	14.68%
Large	1,043	104	939	400	600	43	$15.00	$12.90	$21.30	$1.53	$0.00	$16.67	$38.31	$0.00	$105.71	$10.76	11.33%
XLg	1,810	181	1,629	400	600	810	$15.00	$12.90	$21.30	$28.76	$0.00	$28.92	$66.48	$0.00	$173.36	$14.13	8.87%
AnnAvg	1,008	101	907	400	600	8	$15.00	$12.90	$21.30	$0.29	$0.00	$16.11	$37.03	$0.00	$102.63	$10.63	11.55%
AvgWin	801	80	721	400	401	0	$15.00	$12.90	$14.22	$0.00	$0.00	$12.79	$29.41	$0.00	$84.32	$9.70	13.00%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE - SUPER PEAK

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
	Winter						$11.50	$0.025000	$0.035000	$0.035000	$0.001140	$0.150000	$0.038700	-$0.002139	
	Summer	0.14	0.86									$0.170000	$0.039700		
Xsm	261	37	224	261	0	0	$11.50	$6.53	$0.00	$0.00	$0.30	$6.21	$8.91	-$0.56	$32.89
Small	525	74	452	400	125	0	$11.50	$10.00	$4.38	$0.00	$0.60	$12.50	$17.92	-$1.12	$55.78
Medium	983	138	845	400	583	0	$11.50	$10.00	$20.41	$0.00	$1.12	$23.40	$33.56	-$2.10	$97.89
Large	1,611	226	1,385	400	600	611	$11.50	$10.00	$21.00	$21.39	$1.84	$38.34	$55.00	-$3.45	$155.62
XLg	2,681	375	2,306	400	600	1,681	$11.50	$10.00	$21.00	$58.84	$3.06	$63.81	$91.53	-$5.74	$254.00
AnnAvg	1,008	141	867	400	600	8	$11.50	$10.00	$21.00	$0.28	$1.15	$23.99	$34.42	-$2.16	$100.18
AvgSum	1,195	167	1,027	400	600	195	$11.50	$10.00	$21.00	$6.82	$1.36	$28.43	$40.79	-$2.56	$117.34

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+							
	Winter						$15.00	$0.032258	$0.035500	$0.035500	$0.000000	$0.159790	$0.040810				
	Summer	0.14	0.86									$0.159790	$0.040810	0.000%			
Xsm	261	37	224	261	0	0	$15.00	$8.42	$0.00	$0.00	$0.00	$5.84	$9.16	$0.00	$38.42	$5.53	16.81%
Small	525	74	452	400	125	0	$15.00	$12.90	$4.44	$0.00	$0.00	$11.74	$18.43	$0.00	$62.51	$6.73	12.07%
Medium	983	138	845	400	583	0	$15.00	$12.90	$20.70	$0.00	$0.00	$21.99	$34.50	$0.00	$105.09	$7.20	7.36%
Large	1,611	226	1,385	400	600	611	$15.00	$12.90	$21.30	$21.69	$0.00	$36.04	$56.54	$0.00	$163.47	$7.85	5.04%
XLg	2,681	375	2,306	400	600	1,681	$15.00	$12.90	$21.30	$59.68	$0.00	$59.98	$94.09	$0.00	$262.95	$8.95	3.52%
AnnAvg	1,008	141	867	400	600	8	$15.00	$12.90	$21.30	$0.29	$0.00	$22.55	$35.38	$0.00	$107.42	$7.24	7.22%
AvgSum	1,195	167	1,027	400	600	195	$15.00	$12.90	$21.30	$6.91	$0.00	$26.73	$41.93	$0.00	$124.77	$7.43	6.33%

	Net Bill	$ Change	% Change
Current Annual	$1,151.78		
Proposed Annual	$1,254.54	$102.76	8.92%

SMALL GENERAL SERVICE

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery kWh			Basic Service Charge	Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill
		1-400	401-7500	7501+		1-400	401-7500	7501+				
					$14.50	$0.030176	$0.041042	$0.076042	$0.001140	$0.058241	-$0.002139	
Xsm	200	200	0	0	$14.50	$6.04	$0.00	$0.00	$0.23	$11.65	-$0.43	$31.99
Small	350	350	0	0	$14.50	$10.56	$0.00	$0.00	$0.40	$20.38	-$0.75	$45.09
Medium	561	400	161	0	$14.50	$12.07	$6.61	$0.00	$0.64	$32.67	-$1.20	$65.29
Large	1,447	400	1,047	0	$14.50	$12.07	$42.97	$0.00	$1.65	$84.27	-$3.10	$152.36
XLg	4,078	400	3,678	0	$14.50	$12.07	$150.95	$0.00	$4.65	$237.51	-$8.72	$410.96
Mean	1,131	400	731	0	$14.50	$12.07	$30.00	$0.00	$1.29	$65.87	-$2.42	$121.31
sum	1,277	400	877	0	$14.50	$12.07	$36.00	$0.00	$1.46	$74.39	-$2.73	$135.69
win	980	400	580	0	$14.50	$12.07	$23.82	$0.00	$1.12	$57.10	-$2.10	$106.51
Annual												$1,453.20

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery kWh			Basic Service Charge	Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		1-400	401-7500	7501+		1-400	401-7500	7501+						
					$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.053290	0.000%			
Xsm	200	200	0	0	$30.00	$6.48	$0.00	$0.00	$0.00	$10.66	$0.00	$47.14	$15.15	47.35%
Small	350	350	0	0	$30.00	$11.34	$0.00	$0.00	$0.00	$18.65	$0.00	$59.99	$14.90	33.04%
Medium	561	400	161	0	$30.00	$12.96	$6.83	$0.00	$0.00	$29.90	$0.00	$79.69	$14.40	22.06%
Large	1,447	400	1,047	0	$30.00	$12.96	$44.39	$0.00	$0.00	$77.11	$0.00	$164.46	$12.10	7.94%
XLg	4,078	400	3,678	0	$30.00	$12.96	$155.95	$0.00	$0.00	$217.32	$0.00	$416.23	$5.27	1.28%
Mean	1,131	400	731	0	$30.00	$12.96	$30.99	$0.00	$0.00	$60.27	$0.00	$134.22	$12.91	10.64%
sum	1,277	400	877	0	$30.00	$12.96	$37.20	$0.00	$0.00	$68.07	$0.00	$148.23	$12.54	9.24%
win	980	400	580	0	$30.00	$12.96	$24.61	$0.00	$0.00	$52.25	$0.00	$119.82	$13.31	12.49%
Annual												$1,608.30	$155.10	10.67%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE DEMAND

WINTER

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery kWh			Basic Service Charge	Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill
				1-400	401-7500	7501+		1-400	401-7500	7501+				
							$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.053290	$0.000000	
Xsm	27%	0.9	173	173	0	0	$30.00	$5.61	$0.00	$0.00	$0.00	$9.22	$0.00	$44.82
Small	30%	1.4	303	303	0	0	$30.00	$9.82	$0.00	$0.00	$0.00	$16.15	$0.00	$55.96
Medium	33%	2.0	486	400	86	0	$30.00	$12.96	$3.65	$0.00	$0.00	$25.90	$0.00	$72.51
Large	40%	4.3	1,254	400	854	0	$30.00	$12.96	$36.21	$0.00	$0.00	$66.83	$0.00	$146.00
XLg	48%	10.1	3,535	400	3,135	0	$30.00	$12.96	$132.92	$0.00	$0.00	$188.38	$0.00	$364.26
AnnAvg	39%	4.0	1,131	400	731	0	$30.00	$12.96	$30.99	$0.00	$0.00	$60.27	$0.00	$134.22
WinAvg	38%	3.6	980	400	580	0	$30.00	$12.96	$24.61	$0.00	$0.00	$52.25	$0.00	$119.82

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak	30.00	All kW 5.49	All kWh $0.016680	$0.000000	On-Peak	Off-Peak				
	Winter			0.30	0.70					$0.083570	$0.040036	0.000%			
	Summer									$0.084570	$0.045800				
Xsm	27%	0.9	173	53	120	$30.00	$4.94	$2.89	$0.00	$4.39	$4.82	$0.00	$47.04	$2.22	4.94%
Small	30%	1.4	303	92	211	$30.00	$7.69	$5.05	$0.00	$7.70	$8.44	$0.00	$58.88	$2.92	5.21%
Medium	33%	2.0	486	148	338	$30.00	$10.98	$8.11	$0.00	$12.35	$13.54	$0.00	$74.98	$2.47	3.41%
Large	40%	4.3	1,254	381	873	$30.00	$23.61	$20.92	$0.00	$31.86	$34.94	$0.00	$141.33	-$4.67	-3.20%
XLg	48%	10.1	3,535	1,075	2,460	$30.00	$55.45	$58.96	$0.00	$89.80	$98.50	$0.00	$332.71	-$31.55	-8.66%
AnnAvg	39%	4.0	1,131	344	787	$30.00	$21.96	$18.86	$0.00	$28.73	$31.52	$0.00	$131.07	-$3.15	-2.35%
WinAvg	38%	3.6	980	298	682	$30.00	$19.76	$16.35	$0.00	$24.91	$27.32	$0.00	$118.34	-$1.48	-1.23%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SUMMER

SMALL GENERAL SERVICE DEMAND

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery kWh			Basic Service Charge	Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill
				1-400	401-7500	7501+		1-400	401-7500	7501+				
							$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.053290	$0.000000	
Xsm	29%	1.1	226	226	0	0	$30.00	$7.32	$0.00	$0.00	$0.00	$12.04	$0.00	$49.37
Small	32%	1.7	395	395	0	0	$30.00	$12.80	$0.00	$0.00	$0.00	$21.05	$0.00	$63.85
Medium	35%	2.5	634	400	234	0	$30.00	$12.96	$9.92	$0.00	$0.00	$33.79	$0.00	$86.67
Large	42%	5.4	1,634	400	1,234	0	$30.00	$12.96	$52.32	$0.00	$0.00	$87.08	$0.00	$182.36
XLg	51%	12.5	4,605	400	4,205	0	$30.00	$12.96	$178.29	$0.00	$0.00	$245.40	$0.00	$466.65
AnnAvg	39%	4.0	1,131	400	731	0	$30.00	$12.96	$30.99	$0.00	$0.00	$60.27	$0.00	$134.22
SumAvg	40%	4.4	1,277	400	877	0	$30.00	$12.96	$37.20	$0.00	$0.00	$68.07	$0.00	$148.22

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak		All kW	All kWh							
						30.00	5.49	$0.016680	$0.000000	On-Peak	Off-Peak				
	Winter									$0.083570	$0.040036				
	Summer			0.27	0.73					$0.084570	$0.045800	0.000%			
Xsm	29%	1.1	226	60	166	$30.00	$6.04	$3.77	$0.00	$5.07	$7.61	$0.00	$52.49	$3.12	6.33%
Small	32%	1.7	395	105	290	$30.00	$9.33	$6.59	$0.00	$8.85	$13.30	$0.00	$68.07	$4.22	6.61%
Medium	35%	2.5	634	168	466	$30.00	$13.73	$10.58	$0.00	$14.21	$21.34	$0.00	$89.86	$3.19	3.68%
Large	42%	5.4	1,634	433	1,201	$30.00	$29.65	$27.26	$0.00	$36.62	$55.00	$0.00	$178.53	-$3.83	-2.10%
XLg	51%	12.5	4,605	1,220	3,385	$30.00	$68.63	$76.81	$0.00	$103.21	$155.01	$0.00	$433.66	-$32.99	-7.07%
AnnAvg	39%	4.0	1,131	300	831	$30.00	$21.96	$18.86	$0.00	$25.35	$38.07	$0.00	$134.24	$0.02	0.01%
SumAvg	40%	4.4	1,277	339	939	$30.00	$24.16	$21.30	$0.00	$28.63	$43.00	$0.00	$147.09	-$1.13	-0.76%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE RATE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23					$16.50	$0.030176	$0.043176	$0.076042	$0.001140	$0.129605	$0.031385	-$0.002139	
	Summer	0.18										$0.129605	$0.039605		
Xsm	394	91	303	394	0	0	$16.50	$11.87	$0.00	$0.00	$0.45	$11.73	$9.51	-$0.84	$49.22
Small	636	146	490	400	236	0	$16.50	$12.07	$10.19	$0.00	$0.73	$18.96	$15.37	-$1.36	$72.46
Medium	1633	376	1,257	400	1,233	0	$16.50	$12.07	$53.24	$0.00	$1.86	$48.68	$39.46	-$3.49	$168.32
Large	2,328	535	1,793	400	1,928	0	$16.50	$12.07	$83.24	$0.00	$2.65	$69.40	$56.26	-$4.98	$235.14
XLg	3,091	711	2,380	400	2,691	0	$16.50	$12.07	$116.19	$0.00	$3.52	$92.14	$74.70	-$6.61	$308.51
WinAvg	1,551	357	1,194	400	1,151	0	$16.50	$12.07	$49.70	$0.00	$1.77	$46.24	$37.48	-$3.32	$160.44

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+							
	Winter	0.23					$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.108800	$0.040036	0.000%			
	Summer	0.18										$0.109800	$0.045800				
Xsm	394	91	303	394	0	0	$30.00	$12.75	$0.00	$0.00	$0.00	$9.85	$12.13	$0.00	$64.73	$15.51	31.52%
Small	636	146	490	400	236	0	$30.00	$12.96	$10.01	$0.00	$0.00	$15.92	$19.61	$0.00	$88.50	$16.04	22.14%
Medium	1,633	376	1,257	400	1,233	0	$30.00	$12.96	$52.28	$0.00	$0.00	$40.86	$50.34	$0.00	$186.44	$18.12	10.77%
Large	2,328	535	1,793	400	1,928	0	$30.00	$12.96	$81.75	$0.00	$0.00	$58.26	$71.77	$0.00	$254.74	$19.60	8.34%
XLg	3,091	711	2,380	400	2,691	0	$30.00	$12.96	$114.10	$0.00	$0.00	$77.35	$95.29	$0.00	$329.70	$21.19	6.87%
WinAvg	1,551	357	1,194	400	1,151	0	$30.00	$12.96	$48.81	$0.00	$0.00	$38.81	$47.82	$0.00	$178.40	$17.96	11.19%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE RATE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) On-Peak	Delivery (kWh) Off-Peak	Delivery (kWh) TIERS 0-400	Delivery (kWh) TIERS 401-7,500	Delivery (kWh) TIERS 7,500+	Basic Service Charge	Delivery All kWh 0-400	Delivery All kWh 401-7,500	Delivery All kWh 7,500+	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
	Winter	0.23					$16.50	$0.030176	$0.043176	$0.076042	$0.001140	$0.129605	$0.031385	-$0.002139	
	Summer	0.18										$0.129605	$0.039605		
Xsm	781	141	640	400	381	0	$16.50	$12.07	$16.45	$0.00	$0.89	$18.22	$25.36	-$1.67	$87.82
Small	1220	220	1,000	400	820	0	$16.50	$12.07	$35.40	$0.00	$1.39	$28.46	$39.62	-$2.61	$130.83
Medium	2350	423	1,927	400	1,950	0	$16.50	$12.07	$84.17	$0.00	$2.68	$54.81	$76.30	-$5.03	$241.50
Large	3,078	554	2,524	400	2,678	0	$16.50	$12.07	$115.63	$0.00	$3.51	$71.81	$99.96	-$6.58	$312.90
XLg	3,640	655	2,985	400	3,240	0	$16.50	$12.07	$139.89	$0.00	$4.15	$84.92	$118.21	-$7.79	$367.95
SumAvg	2,256	406	1,850	400	1,856	0	$16.50	$12.07	$80.15	$0.00	$2.57	$52.64	$73.28	-$4.83	$232.38

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) On-Peak	Delivery (kWh) Off-Peak	Delivery (kWh) TIERS 0-400	Delivery (kWh) TIERS 401-7,500	Delivery (kWh) TIERS 7,500+	Basic Service Charge	Delivery All kWh 0-400	Delivery All kWh 401-7,500	Delivery All kWh 7,500+	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
	Winter	0.23					$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.108800	$0.040036				
	Summer	0.18										$0.109800	$0.045800	0.000%			
Xsm	781	141	640	400	381	0	$30.00	$12.96	$16.15	$0.00	$0.00	$15.44	$29.33	$0.00	$103.88	$16.06	18.29%
Small	1,220	220	1,000	400	820	0	$30.00	$12.96	$34.77	$0.00	$0.00	$24.11	$45.82	$0.00	$147.66	$16.83	12.86%
Medium	2,350	423	1,927	400	1,950	0	$30.00	$12.96	$82.66	$0.00	$0.00	$46.44	$88.24	$0.00	$260.30	$18.80	7.78%
Large	3,078	554	2,524	400	2,678	0	$30.00	$12.96	$113.55	$0.00	$0.00	$60.83	$115.60	$0.00	$332.94	$20.04	6.41%
XLg	3,640	655	2,985	400	3,240	0	$30.00	$12.96	$137.38	$0.00	$0.00	$71.94	$136.70	$0.00	$388.98	$21.03	5.71%
SumAvg	2,256	406	1,850	400	1,856	0	$30.00	$12.96	$78.71	$0.00	$0.00	$44.59	$84.74	$0.00	$251.00	$18.62	8.01%

	Net Bill	$ Change	% Change
Current Annual	$2,356.95		
Proposed Annual	$2,576.40	$219.45	9.31%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE RATE TIME OF USE DEMAND

WINTER

BILL IMPACTS PROPOSED SGS-TOU RATES

	Energy (kWh)	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23					$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.108800	$0.040036	0.000%	
	Summer	0.18										$0.109800	$0.045800		
Xsm	394	91	303	394	0	0	$30.00	$12.75	$0.00	$0.00	$0.00	$9.85	$12.13	$0.00	$64.73
Small	636	146	490	400	236	0	$30.00	$12.96	$10.01	$0.00	$0.00	$15.92	$19.61	$0.00	$88.50
Medium	1633	376	1,257	400	1,233	0	$30.00	$12.96	$52.28	$0.00	$0.00	$40.86	$50.34	$0.00	$186.44
Large	2,328	535	1,793	400	1,928	0	$30.00	$12.96	$81.75	$0.00	$0.00	$58.26	$71.77	$0.00	$254.74
XLg	3,091	711	2,380	400	2,691	0	$30.00	$12.96	$114.10	$0.00	$0.00	$77.35	$95.29	$0.00	$329.70
WinAvg	1,551	357	1,194	400	1,151	0	$30.00	$12.96	$48.81	$0.00	$0.00	$38.81	$47.82	$0.00	$178.40

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)			Basic Service Charge	Delivery		TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak						All kW	All kWh							
								30.00	5.49	$0.016680	$0.000000	On-Peak	Off-Peak				
	Winter	0.23										$0.083570	$0.040036	0.000%			
	Summer	0.18										$0.084570	$0.045800				
Xsm	394	91	303	32%	1.7			$30.00	$9.33	$6.56	$0.00	$7.56	$12.13	$0.00	$65.58	$0.85	1.31%
Small	636	146	490	35%	2.5			$30.00	$13.73	$10.61	$0.00	$12.22	$19.61	$0.00	$86.17	-$2.33	-2.63%
Medium	1633	376	1,257	42%	5.4			$30.00	$29.65	$27.24	$0.00	$31.39	$50.34	$0.00	$168.62	-$17.82	-9.56%
Large	2,328	535	1,793	44%	7.2			$30.00	$39.53	$38.83	$0.00	$44.75	$71.77	$0.00	$224.88	-$29.86	-11.72%
XLg	3,091	711	2,380	47%	9.0			$30.00	$49.41	$51.56	$0.00	$59.41	$95.29	$0.00	$285.67	-$44.03	-13.35%
WinAvg	1,551	357	1,194	41%	5.2			$30.00	$28.55	$25.87	$0.00	$29.81	$47.82	$0.00	$162.05	-$16.35	-9.16%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE RATE TIME OF USE DEMAND

SUMMER

BILL IMPACTS PROPOSED SGS-TOU RATES

	Energy (kWh)	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23					$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.108800	$0.040036		
	Summer	0.18										$0.109800	$0.045800	0.000%	
Xsm	781	141	640	400	381	0	$30.00	$12.96	$16.15	$0.00	$0.00	$15.44	$29.33	$0.00	$103.88
Small	1220	220	1,000	400	820	0	$30.00	$12.96	$34.77	$0.00	$0.00	$24.11	$45.82	$0.00	$147.66
Medium	2350	423	1,927	400	1,950	0	$30.00	$12.96	$82.66	$0.00	$0.00	$46.44	$88.24	$0.00	$260.30
Large	3,078	554	2,524	400	2,678	0	$30.00	$12.96	$113.55	$0.00	$0.00	$60.83	$115.60	$0.00	$332.94
XLg	3,640	655	2,985	400	3,240	0	$30.00	$12.96	$137.38	$0.00	$0.00	$71.94	$136.70	$0.00	$388.98
SumAvg	2,256	406	1,850	400	1,856	0	$30.00	$12.96	$78.71	$0.00	$0.00	$44.59	$84.74	$0.00	$251.00

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)			Basic Service Charge	Delivery		TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
									All kW	All kWh							
		On-Peak	Off-Peak					30.00	5.49	$0.016680	$0.000000	On-Peak	Off-Peak				
	Winter	0.23										$0.083570	$0.040036				
	Summer	0.18										$0.084570	$0.045800	0.000%			
Xsm	781	141	640	36%	3.0			$30.00	$16.47	$13.03	$0.00	$11.89	$29.33	$0.00	$100.72	-$3.16	-3.04%
Small	1,220	220	1,000	39%	4.3			$30.00	$23.61	$20.35	$0.00	$18.57	$45.82	$0.00	$138.35	-$9.31	-6.31%
Medium	2,350	423	1,927	45%	7.2			$30.00	$39.53	$39.19	$0.00	$35.77	$88.24	$0.00	$232.73	-$27.57	-10.59%
Large	3,078	554	2,524	47%	9.0			$30.00	$49.41	$51.34	$0.00	$46.86	$115.60	$0.00	$293.21	-$39.73	-11.93%
XLg	3,640	655	2,985	48%	10.3			$30.00	$56.55	$60.72	$0.00	$55.41	$136.70	$0.00	$339.38	-$49.60	-12.75%
SumAvg	2,256	406	1,850	44%	7.0			$30.00	$38.43	$37.64	$0.00	$34.35	$84.74	$0.00	$225.16	-$25.84	-10.29%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

		$ Change	% Change
Current Annual	$2,576.40		
Proposed Annual	$2,323.26	[illegible]	-9.83%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

INTERRUPTIBLE POWER SERVICE

	BILL IMPACTS CURRENT RATES									
	Load Factor	Total kWh	Demand (kW)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$18.00	$5.00	$0.019408	$0.432900	0.043760	-$0.002139	
Xsm	40.3%	1,116	66	$18.00	$331.53	$21.65	$28.70	$48.82	-$2.39	$446.32
Small	27.4%	14,651	108	$18.00	$541.23	$284.34	$46.86	$641.11	-$31.34	$1,500.20
Medium	30.7%	29,389	154	$18.00	$768.97	$570.39	$66.58	$1,286.08	-$62.87	$2,647.15
Large	44.3%	71,334	237	$18.00	$1,183.91	$1,384.44	$102.50	$3,121.55	-$152.61	$5,657.79
XLg	58.4%	384,599	887	$18.00	$4,432.94	$7,464.30	$383.80	$16,830.06	-$822.79	$28,306.31
AnnAvg	56.0%	97,708	239	$18.00	$1,195.06	$1,896.33	$103.47	$4,275.72	-$209.03	$7,279.55
AvgWin	52.0%	83,072	219	$18.00	$1,094.21	$1,612.26	$94.74	$3,635.24	-$177.72	$6,276.73
AvgSum	62.0%	112,958	250	$18.00	$1,247.88	$2,192.29	$108.04	$4,943.03	-$241.65	$8,267.58
Annual										$87,265.86

	BILL IMPACTS PROPOSED RATES											
	Load Factor	Total kWh	Demand (kW)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$75.00	$5.50	$0.019800	$0.000000	$0.053090	0.000%			
Xsm	40.3%	1,116	66	$75.00	$364.69	$22.09	$0.00	$59.23	$0.00	$521.01	$74.69	16.73%
Small	27.4%	14,651	108	$75.00	$595.36	$290.08	$0.00	$777.80	$0.00	$1,738.24	$238.04	15.87%
Medium	30.7%	29,389	154	$75.00	$845.87	$581.91	$0.00	$1,560.28	$0.00	$3,063.06	$415.91	15.71%
Large	44.3%	71,334	237	$75.00	$1,302.30	$1,412.40	$0.00	$3,787.10	$0.00	$6,576.80	$919.01	16.24%
XLg	58.4%	384,599	887	$75.00	$4,876.23	$7,615.06	$0.00	$20,418.37	$0.00	$32,984.66	$4,678.35	16.53%
AnnAvg	56.0%	97,708	239	$75.00	$1,314.57	$1,934.63	$0.00	$5,187.34	$0.00	$8,511.54	$1,231.99	16.92%
AvgWin	52.0%	83,072	219	$75.00	$1,203.63	$1,644.83	$0.00	$4,410.30	$0.00	$7,333.76	$1,057.03	16.84%
AvgSum	62.0%	112,958	250	$75.00	$1,372.66	$2,236.57	$0.00	$5,996.93	$0.00	$9,681.16	$1,413.59	17.10%
Annual										$102,089.53	$14,823.67	16.99%

MEDIUM GENERAL SERVICE

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$50.00	$12.81	$0.005470	$0.432900	$0.056603	-$0.002139	
Xsm	0.46	20	4,040	$50.00	$256.20	$22.10	$8.66	$228.68	-$8.64	$557.00
Small	0.46	20	6,400	$50.00	$256.20	$35.01	$8.66	$362.26	-$13.69	$698.44
Medium	0.46	36	12,160	$50.00	$463.88	$66.52	$15.68	$688.29	-$26.01	$1,258.36
Large	0.46	80	26,880	$50.00	$1,025.41	$147.03	$34.65	$1,521.49	-$57.51	$2,721.07
Xlarge	0.46	294	98,640	$50.00	$3,762.89	$539.56	$127.16	$5,583.32	-$211.02	$9,851.91
AnnAvg	0.46	80	26,796	$50.00	$1,022.22	$146.58	$34.54	$1,516.76	-$57.33	$2,712.77
sum	0.46	90	30,153	$50.00	$1,150.28	$164.94	$38.87	$1,706.76	-$64.51	$3,046.34
win	0.46	70	23,520	$50.00	$897.22	$128.65	$30.32	$1,331.28	-$50.32	$2,387.15
Annual										$32,600.94

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$100.00	$13.95	$0.005500	$0.000000	$0.053290	0.000%			
Xsm	0.46	20	4,040	$100.00	$279.00	$22.22	$0.00	$215.29	$0.00	$616.51	$59.51	10.7%
Small	0.46	20	6,400	$100.00	$279.00	$35.20	$0.00	$341.06	$0.00	$755.26	$56.82	8.1%
Medium	0.46	36	12,160	$100.00	$505.16	$66.88	$0.00	$648.01	$0.00	$1,320.05	$61.69	4.9%
Large	0.46	80	26,880	$100.00	$1,116.66	$147.84	$0.00	$1,432.44	$0.00	$2,796.94	$75.87	2.8%
Xlarge	0.46	294	98,640	$100.00	$4,097.76	$542.52	$0.00	$5,256.53	$0.00	$9,996.81	$144.90	1.5%
AnnAvg	0.46	80	26,796	$100.00	$1,113.19	$147.38	$0.00	$1,427.98	$0.00	$2,788.55	$75.78	2.8%
sum	0.46	90	30,153	$100.00	$1,252.64	$165.84	$0.00	$1,606.87	$0.00	$3,125.35	$79.01	2.6%
win	0.46	70	23,520	$100.00	$977.06	$129.36	$0.00	$1,253.36	$0.00	$2,459.78	$72.63	3.0%
Annual										$33,510.78	$909.84	2.8%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

MEDIUM GENERAL SERVICE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
		Winter		0.29		$52.00	$12.81	$0.005470	$0.43290	0.114886	0.026168	-$0.002139	
		Summer		0.20						0.114886	0.039886		
Xsm	0.46	27,974	83	8,112	19,862	$52.00	$1,067.14	$153.02	$36.06	$932.01	$519.74	-$59.85	$2,700.12
Small	0.46	28,067	84	8,139	19,928	$52.00	$1,070.69	$153.53	$36.18	$935.11	$521.46	-$60.04	$2,708.93
Medium	0.46	48,453	144	14,051	34,402	$52.00	$1,848.37	$265.04	$62.46	$1,614.31	$900.22	-$103.66	$4,638.74
Large	0.56	62,572	186	18,146	44,426	$52.00	$2,386.98	$342.27	$80.67	$2,084.71	$1,162.54	-$133.86	$5,975.31
XLg	0.66	193,470	576	56,106	137,364	$52.00	$7,380.44	$1,058.28	$249.41	$6,445.83	$3,594.53	-$413.90	$18,366.59
AnnAvg	0.58	69,713	208	20,217	49,496	$52.00	$2,659.39	$381.33	$89.87	$2,322.62	$1,295.22	-$149.14	$6,651.29
AvgWin	0.56	65,673	196	19,045	46,628	$52.00	$2,505.28	$359.23	$84.66	$2,188.02	$1,220.16	-$140.50	$6,268.85

BILL IMPACTS PROPOSED RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
		Winter				$100.00	$13.95	$0.005500	$0.00000	0.101047	0.031690	0.000%			
		Summer								0.114886	0.033500				
Xsm	0.46	27,974	83	8,112	19,862	$100.00	$1,162.11	$153.86	$0.00	$819.74	$629.41	$0.00	$2,865.12	$165.00	6.1%
Small	0.46	28,067	84	8,139	19,928	$100.00	$1,165.98	$154.37	$0.00	$822.46	$631.50	$0.00	$2,874.31	$165.38	6.1%
Medium	0.46	48,453	144	14,051	34,402	$100.00	$2,012.86	$266.49	$0.00	$1,419.85	$1,090.19	$0.00	$4,889.39	$250.65	5.4%
Large	0.56	62,572	186	18,146	44,426	$100.00	$2,599.40	$344.15	$0.00	$1,833.59	$1,407.86	$0.00	$6,285.00	$309.69	5.2%
XLg	0.66	193,470	576	56,106	137,364	$100.00	$8,037.24	$1,064.09	$0.00	$5,669.37	$4,353.06	$0.00	$19,223.76	$857.17	4.7%
AnnAvg	0.58	69,713	208	20,217	49,496	$100.00	$2,896.06	$383.42	$0.00	$2,042.84	$1,568.53	$0.00	$6,990.85	$339.56	5.1%
AvgWin	0.56	65,673	196	19,045	46,628	$100.00	$2,728.23	$361.20	$0.00	$1,924.46	$1,477.64	$0.00	$6,591.53	$322.68	5.1%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

MEDIUM GENERAL SERVICE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
		Winter		0.29		$52.00	$12.81	$0.005470	$0.43290	0.114886	0.026168		
		Summer		0.20									
Xsm	0.46	27,974	83	5,595	22,379	$52.00	$1,067.14	$153.02	$36.06	0.114886	0.039886	-$0.002139	
Small	0.46	28,067	84	5,613	22,454	$52.00	$1,070.69	$153.53	$36.18	$642.76	$892.62	-$59.85	$2,783.75
Medium	0.46	48,453	144	9,691	38,762	$52.00	$1,848.37	$265.04	$62.46	$644.90	$895.58	-$60.04	$2,792.84
Large	0.56	62,572	186	12,514	50,058	$52.00	$2,386.98	$342.27	$80.67	$1,113.31	$1,546.08	-$103.66	$4,783.60
XLg	0.66	193,470	576	38,694	154,776	$52.00	$7,380.44	$1,058.28	$249.41	$1,437.73	$1,996.60	-$133.86	$6,162.39
AnnAvg	0.58	69,713	208	13,943	55,770	$52.00	$2,659.39	$381.33	$89.87	$4,445.40	$6,173.40	-$413.90	$18,945.03
AvgSum	0.56	73,609	219	14,722	58,887	$52.00	$2,808.00	$402.64	$94.89	$1,601.81	$2,224.46	-$149.14	$6,859.72
										$1,691.32	$2,348.76	-$157.47	$7,240.14

BILL IMPACTS PROPOSED RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
		Winter				$100.00	$13.95	$0.005500	$0.00000	0.101047	0.031690				
		Summer								0.114886	0.033500	0.000%			
Xsm	0.46	27,974	83	5,595	22,379	$100.00	$1,162.11	$153.86	$0.00	$642.76	$749.70	$0.00	$2,808.43	$24.68	0.9%
Small	0.46	28,067	84	5,613	22,454	$100.00	$1,165.98	$154.37	$0.00	$644.90	$752.20	$0.00	$2,817.45	$24.61	0.9%
Medium	0.46	48,453	144	9,691	38,762	$100.00	$2,012.86	$266.49	$0.00	$1,113.31	$1,298.54	$0.00	$4,791.20	$7.60	0.2%
Large	0.56	62,572	186	12,514	50,058	$100.00	$2,599.40	$344.15	$0.00	$1,437.73	$1,676.93	$0.00	$6,158.21	-$4.18	-0.1%
XLg	0.66	193,470	576	38,694	154,776	$100.00	$8,037.24	$1,064.09	$0.00	$4,445.40	$5,185.00	$0.00	$18,831.73	-$113.30	-0.6%
AnnAvg	0.58	69,713	208	13,943	55,770	$100.00	$2,896.06	$383.42	$0.00	$1,601.81	$1,868.31	$0.00	$6,849.60	-$10.12	-0.1%
AvgSum	0.56	73,609	219	14,722	58,887	$100.00	$3,057.89	$404.85	$0.00	$1,691.32	$1,972.71	$0.00	$7,226.77	-$13.37	-0.2%

	$ Change	% Change	
Current Annual	$81,053.94		
Proposed Annual	$82,909.80	$1,855.86	2.3%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE GENERAL SERVICE TO NEW LARGE GENERAL SERVICE

BILL IMPACTS CURRENT RATES - LGS

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$50.00	$12.81	$0.005470	$0.43290	0.056603	-$0.002139	
Xsm	30%	205	45,000	$50.00	$2,632.19	$246.15	$88.95	$2,547.14	-$96.27	$5,468.16
Small	46%	194	65,000	$50.00	$2,479.60	$355.55	$83.80	$3,679.20	-$139.06	$6,509.09
Medium	66%	844	406,600	$50.00	$10,810.60	$2,224.10	$365.33	$23,014.78	-$869.85	$35,594.96
Large	75%	174	95,000	$50.00	$2,222.74	$519.65	$75.12	$5,377.29	-$203.24	$8,041.56
XLg	95%	1,875	1,300,500	$50.00	$24,022.21	$7,113.74	$811.80	$73,612.20	-$2,782.20	$102,827.75
AnnAvg	65%	992	470,630	$50.00	$12,705.52	$2,574.35	$429.37	$26,639.07	-$1,006.83	$41,391.47

BILL IMPACTS PROPOSED RATES - LGS

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$300.00	$13.35	$0.005470	$0.00000	$0.053290	0.000%			
Xsm	30%	450	45,000	$300.00	$6,007.50	$246.15	$0.00	$2,398.05	$0.00	$8,951.70	$3,483.54	63.7%
Small	46%	450	65,000	$300.00	$6,007.50	$355.55	$0.00	$3,463.85	$0.00	$10,126.90	$3,617.81	55.6%
Medium	66%	844	406,600	$300.00	$11,266.31	$2,224.10	$0.00	$21,667.71	$0.00	$35,458.13	-$136.83	-0.4%
Large	75%	450	95,000	$300.00	$6,007.50	$519.65	$0.00	$5,062.55	$0.00	$11,889.70	$3,848.14	47.9%
XLg	95%	1,875	1,300,500	$300.00	$25,034.86	$7,113.74	$0.00	$69,303.65	$0.00	$101,752.24	-$1,075.50	-1.0%
AnnAvg	65%	992	470,630	$300.00	$13,241.12	$2,574.35	$0.00	$25,079.87	$0.00	$41,195.33	-$196.14	-0.5%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE <69kV TO NEW LARGE GENERAL SERVICE

BILL IMPACTS CURRENT RATES - LPS <69kV

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$1,200.00	$22.00	$0.000462	$0.43290	$0.04188	-$0.002139	
Xsm	44%	747	240,000	$1,200.00	$16,438.36	$110.88	$323.46	$10,051.20	-$513.44	$27,610.46
Small	46%	893	300,000	$1,200.00	$19,654.56	$138.60	$386.75	$12,564.00	-$641.80	$33,302.11
Medium	66%	844	406,600	$1,200.00	$18,566.21	$187.85	$365.33	$17,028.41	-$869.85	$36,477.95
Large	75%	1,553	850,000	$1,200.00	$34,155.25	$392.70	$672.08	$35,598.00	-$1,818.43	$70,199.60
XLg	75%	2,192	1,200,000	$1,200.00	$48,219.18	$554.40	$948.82	$50,256.00	-$2,567.20	$98,611.20
AnnAvg	65%	992	470,630	$1,200.00	$21,820.57	$217.43	$429.37	$19,709.98	-$1,006.83	$42,370.52

BILL IMPACTS PROPOSED RATES - LPS <69 kV

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$300.00	$13.35	$0.005470	$0.00000	$0.053290	0.000%			
Xsm	44%	747	240,000	$300.00	$9,975.09	$1,312.80	$0.00	$12,789.60	$0.00	$24,377.49	-$3,232.96	-11.7%
Small	46%	893	300,000	$300.00	$11,926.74	$1,641.00	$0.00	$15,987.00	$0.00	$29,854.74	-$3,447.36	-10.4%
Medium	66%	844	406,600	$300.00	$11,266.31	$2,224.10	$0.00	$21,667.71	$0.00	$35,458.13	-$1,019.82	-2.8%
Large	75%	1,553	850,000	$300.00	$20,726.03	$4,649.50	$0.00	$45,296.50	$0.00	$70,972.03	$772.43	1.1%
XLg	75%	2,192	1,200,000	$300.00	$29,260.27	$6,564.00	$0.00	$63,948.00	$0.00	$100,072.27	$1,461.08	1.5%
AnnAvg	65%	992	470,630	$300.00	$13,241.12	$2,574.35	$0.00	$25,079.87	$0.00	$41,195.33	-$1,175.18	-2.8%

LARGE POWER SERVICE TIME OF USE <69kV TO NEW LARGE GENERAL SERVICE TIME OF USE

WINTER

	BILL IMPACTS CURRENT RATES											
	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
	Winter		0.16		$1,200.00	$22.00	$0.000462	$0.43290	$0.093880	$0.022105	-$0.002139	
	Summer		0.16						$0.123580	$0.024716		
Small	433,335	1,281	69,334	364,001	$1,200.00	$28,182.00	$200.20	$554.54	$6,509.04	$8,046.25	-$927.05	$43,764.98
Medium	517,000	1,380	82,720	434,280	$1,200.00	$30,360.00	$238.85	$597.40	$7,765.75	$9,599.76	-$1,106.04	$48,655.72
Large	600,000	1,400	96,000	504,000	$1,200.00	$30,800.00	$277.20	$606.06	$9,012.48	$11,140.92	-$1,283.60	$51,753.06
XLg	775,000	1,570	124,000	651,000	$1,200.00	$34,540.00	$358.05	$679.65	$11,641.12	$14,390.36	-$1,657.98	$61,151.20
Mean	642,400	1,430	102,784	539,616	$1,200.00	$31,460.00	$296.79	$619.05	$9,649.36	$11,928.21	-$1,374.31	$53,779.10
AvgWin	627,900	1,416	100,464	527,436	$1,200.00	$31,152.00	$290.09	$612.99	$9,431.56	$11,658.97	-$1,343.29	$53,002.32

	BILL IMPACTS PROPOSED RATES													
	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
	Winter				$300.00	$13.35	$0.005470	$0.00000	$0.139880	$0.034927	0.000%			
	Summer								$0.143771	$0.038600				
Small	433,335	1,281	69,334	364,001	$300.00	$17,101.35	$2,370.34	$0.00	$9,698.38	$12,713.48	$0.00	$42,183.55	-$1,581.43	-3.6%
Medium	517,000	1,380	82,720	434,280	$300.00	$18,423.00	$2,827.99	$0.00	$11,570.87	$15,168.10	$0.00	$48,289.96	-$365.76	-0.8%
Large	600,000	1,400	96,000	504,000	$300.00	$18,690.00	$3,282.00	$0.00	$13,428.48	$17,603.21	$0.00	$53,303.69	$1,550.63	3.0%
XLg	775,000	1,570	124,000	651,000	$300.00	$20,959.50	$4,239.25	$0.00	$17,345.12	$22,737.48	$0.00	$65,581.35	$4,430.15	7.2%
Mean	642,400	1,430	102,784	539,616	$300.00	$19,090.50	$3,513.93	$0.00	$14,377.43	$18,847.17	$0.00	$56,129.03	$2,349.93	4.4%
AvgWin	627,900	1,416	100,464	527,436	$300.00	$18,903.60	$3,434.61	$0.00	$14,052.90	$18,421.76	$0.00	$55,112.87	$2,110.55	4.0%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE - TRANSMISSION VOLTAGE

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$1,200.00	$17.00	$0.000462	$0.43290	$0.041880	-$0.002139	
Xsm	0.42	506	155,000	$1,200.00	$8,594.26	$71.61	$218.85	$6,491.40	-$331.60	$16,244.52
Small	0.42	1,267	388,500	$1,200.00	$21,541.10	$179.49	$548.54	$16,270.38	-$831.13	$38,908.37
Small	0.46	1,336	448,600	$1,200.00	$22,710.54	$207.25	$578.32	$18,787.37	-$959.70	$42,523.79
Medium	0.75	2,416	1,322,700	$1,200.00	$41,070.14	$611.09	$1,045.84	$55,394.68	-$2,829.70	$96,492.04
Medium	0.75	2,817	1,542,200	$1,200.00	$47,885.66	$712.50	$1,219.39	$64,587.34	-$3,299.28	$112,305.61
Large	0.89	4,775	3,102,500	$1,200.00	$81,179.78	$1,433.36	$2,067.22	$129,932.70	-$6,637.28	$209,175.77
Large	0.89	5,379	3,494,900	$1,200.00	$91,447.28	$1,614.64	$2,328.68	$146,366.41	-$7,476.76	$235,480.26

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$1,500.00	$13.00	$0.000500	$0.00000	$0.049332	0.000%			
Xsm	0.42	506	155,000	$1,500.00	$6,572.08	$77.50	$0.00	$7,646.43	$0.00	$15,796.01	-$448.51	-2.8%
Small	0.42	1,267	388,500	$1,500.00	$16,472.60	$194.25	$0.00	$19,165.41	$0.00	$37,332.26	-$1,576.11	-4.1%
Small	0.46	1,336	448,600	$1,500.00	$17,366.89	$224.30	$0.00	$22,130.26	$0.00	$41,221.45	-$1,302.34	-3.1%
Medium	0.75	2,416	1,322,700	$1,500.00	$31,406.58	$661.35	$0.00	$65,251.21	$0.00	$98,819.14	$2,327.09	2.4%
Medium	0.75	2,817	1,542,200	$1,500.00	$36,618.45	$771.10	$0.00	$76,079.54	$0.00	$114,969.09	$2,663.48	2.4%
Large	0.89	4,775	3,102,500	$1,500.00	$62,078.65	$1,551.25	$0.00	$153,051.99	$0.00	$218,181.89	$9,006.12	4.3%
Large	0.89	5,379	3,494,900	$1,500.00	$69,930.28	$1,747.45	$0.00	$172,409.80	$0.00	$245,587.53	$10,107.27	4.3%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

Exhibit CAJ-R-4

Schedule H-4

LARGE POWER SERVICE TIME OF USE >69kV

WINTER

BILL IMPACTS CURRENT RATES

	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill
	Winter				$1,200.00	$17.00	$0.000462	$0.43290	$0.093880	$0.022105	-$0.002139	
	Summer		0.11	0.89					$0.123580	$0.024716		
Small	2,790,000	5,083	306,900	2,483,100	$1,200.00	$86,411.00	$1,288.98	$2,200.43	$28,811.77	$54,888.93	-$5,967.81	$168,833.30
Medium	3,150,000	5,083	346,500	2,803,500	$1,200.00	$86,411.00	$1,455.30	$2,200.43	$32,529.42	$61,971.37	-$6,737.85	$179,029.67
Large	2,115,000	5,083	232,650	1,882,350	$1,200.00	$86,411.00	$977.13	$2,200.43	$21,841.18	$41,609.35	-$4,523.99	$149,715.10
Mean	2,717,000	5,083	298,870	2,418,130	$1,200.00	$86,411.00	$1,255.25	$2,200.43	$28,057.92	$53,452.76	-$5,811.66	$166,765.70
AvgWin	2,726,000	5,083	299,860	2,426,140	$1,200.00	$86,411.00	$1,259.41	$2,200.43	$28,150.86	$53,629.82	-$5,830.91	$167,020.61

BILL IMPACTS PROPOSED RATES

	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill	$ Change	% Change
	Winter				$1,500.00	$13.00	$0.000500	$0.00000	$0.092110	$0.030410	0.000%			
	Summer								$0.125155	$0.033410				
Small	2,790,000	5,083	306,900	2,483,100	$1,500.00	$66,079.00	$1,395.00	$0.00	$28,268.56	$75,511.07	$0.00	$172,753.63	$3,920.33	2.32%
Medium	3,150,000	5,083	346,500	2,803,500	$1,500.00	$66,079.00	$1,575.00	$0.00	$31,916.12	$85,254.44	$0.00	$186,324.56	$7,294.89	4.07%
Large	2,115,000	5,083	232,650	1,882,350	$1,500.00	$66,079.00	$1,057.50	$0.00	$21,429.39	$57,242.26	$0.00	$147,308.15	-$2,406.95	-1.61%
Mean	2,717,000	5,083	298,870	2,418,130	$1,500.00	$66,079.00	$1,358.50	$0.00	$27,528.92	$73,535.33	$0.00	$170,001.75	$3,236.05	1.94%
AvgWin	2,726,000	5,083	299,860	2,426,140	$1,500.00	$66,079.00	$1,363.00	$0.00	$27,620.10	$73,778.92	$0.00	$170,341.02	$3,320.41	1.99%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE TIME OF USE >69kV

SUMMER

BILL IMPACTS CURRENT RATES

	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill
	Winter				$1,200.00	$17.00	$0.000462	$0.43290	$0.093880	$0.022105		
	Summer		0.11	0.89					$0.123580	$0.024716	-$0.002139	
Small	2,790,000	5,083	306,900	2,483,100	$1,200.00	$86,411.00	$1,288.98	$2,200.43	$37,926.70	$61,372.30	-$5,967.81	$184,431.60
Medium	3,150,000	5,083	346,500	2,803,500	$1,200.00	$86,411.00	$1,455.30	$2,200.43	$42,820.47	$69,291.31	-$6,737.85	$196,640.66
Large	2,115,000	5,083	232,650	1,882,350	$1,200.00	$86,411.00	$977.13	$2,200.43	$28,750.89	$46,524.16	-$4,523.99	$161,539.62
Mean	2,717,000	5,083	298,870	2,418,130	$1,200.00	$86,411.00	$1,255.25	$2,200.43	$36,934.35	$59,766.50	-$5,811.66	$181,955.87
AvgSum	2,790,000	5,083	311,600	2,478,400	$1,200.00	$86,411.00	$1,288.98	$2,200.43	$38,507.53	$61,256.13	-$5,967.81	$184,896.26

BILL IMPACTS PROPOSED RATES

	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill	$ Change	% Change
	Winter				$1,500.00	$13.00	$0.000500	$0.00000	$0.092110	$0.030410				
	Summer								$0.125155	$0.033410	0.000%			
Small	2,790,000	5,083	306,900	2,483,100	$1,500	$66,079	$1,395	$0.00	$38,410.07	$82,960.37	$0.00	$190,344	$5,912.84	3.21%
Medium	3,150,000	5,083	346,500	2,803,500	$1,500	$66,079	$1,575	$0.00	$43,366.21	$93,664.94	$0.00	$206,185	$9,544.49	4.85%
Large	2,115,000	5,083	232,650	1,882,350	$1,500	$66,079	$1,058	$0.00	$29,117.31	$62,889.31	$0.00	$160,643	-$896.50	-0.55%
Mean	2,717,000	5,083	298,870	2,418,130	$1,500	$66,079	$1,359	$0.00	$37,405.07	$80,789.72	$0.00	$187,132	$5,176.42	2.84%
AvgSum	2,790,000	5,083	311,600	2,478,400	$1,500	$66,079	$1,395	$0.00	$38,998.30	$82,803.34	$0.00	$190,776	$5,879.38	3.18%

	Total Net Bill	$ Change	% Change
Current Annual	$2,111,501		
Proposed Annual	$2,166,700	$55,199	2.61%

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

LIGHTING SERVICE

Description	Old Rate	New Rate
New 30' Wood Pole (Class 6) - Overhead	$4.34	$4.68
New 30' Metal or Fiberglass - Overhead	$8.66	$9.35
Existing Wood Pole - Underground	$2.18	$2.35
New 30' Wood Pole (Class 6) - Underground	$6.52	$7.04
New 30' Metal or Fiberglass - Underground	$10.81	$11.67
Wattage, per Watt	$0.051681	$0.060516
Base Power Supply	$0.010113	$0.014535
PPFAC	-$0.002139	0.000%

		Proration
New Rate Days	28	100%
Old Rate Days	0	0%

Total Days	28
Total kWh billed	150

Customer Bill	Current Rates	Proposed Rates	$Change	%Change
100 Watt	$5.17	$6.05	$0.88	17.02%
150 Watt	$7.75	$9.08	$1.33	17.16%
200 Watt	$10.34	$12.10	$1.76	17.02%
250 Watt	$12.92	$15.13	$2.21	17.11%
400 Watt	$20.67	$24.21	$3.54	17.13%
Existing Wood Pole OH	$4.34	$4.68	$0.34	7.83%
New 30' Wood Pole OH	$8.66	$9.35	$0.69	7.97%
New 30' Metal or FG OH	$2.18	$2.35	$0.17	7.80%
Existing Wood Pole UG	$6.52	$7.04	$0.52	7.98%
New 30' Wood Pole UG	$10.81	$11.67	$0.86	7.96%
New 30' Metal or FG UG	$0.05	$0.06	$0.01	17.10%
Base Power Supply	$1.52	$2.18	$0.66	43.42%
PPFAC	($0.32)	$0.00	$0.32	-100.00%
Typical	$13.29	$15.94	$2.65	19.94%

Detail of Services Billed	Wattage	Units Billed
100 Watt	100	1
150 Watt	150	1
200 Watt	200	1
250 Watt	250	1
400 Watt	400	1
Existing Wood Pole OH		5
New 30' Wood Pole OH		0
New 30' Metal or FG OH		0
Existing Wood Pole UG		0
New 30' Wood Pole UG		0
New 30' Metal or FG UG		0

Exhibit CAJ-R-5

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill
		0-400	401-1,000	1,000+	$10.00	$0.019300	$0.034350	$0.038499	$0.001140	$0.064510	-$0.002139	
Xsmall	111	111	0	0	$10.00	$2.14	$0.00	$0.00	$0.13	$7.16	-$0.24	$19.19
Small	330	330	0	0	$10.00	$6.37	$0.00	$0.00	$0.38	$21.29	-$0.71	$37.33
Medium	664	400	264	0	$10.00	$7.72	$9.07	$0.00	$0.76	$42.83	-$1.42	$68.96
Large	1,144	400	600	144	$10.00	$7.72	$20.61	$5.54	$1.30	$73.80	-$2.45	$116.53
Xlarge	2,162	400	600	1,162	$10.00	$7.72	$20.61	$44.74	$2.46	$139.47	-$4.63	$220.37
Mean	830	400	430	0	$10.00	$7.72	$14.75	$0.00	$0.95	$53.51	-$1.77	$85.16
Sum	983	400	583	0	$10.00	$7.72	$20.04	$0.00	$1.12	$63.43	-$2.10	$100.20
Win	669	400	269	0	$10.00	$7.72	$9.25	$0.00	$0.76	$43.18	-$1.43	$69.48
Annual												$1,018.12

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		0-400	401-1,000	1,000+	$15.00	$0.032258	$0.042258	$0.060258	$0.000000	$0.055090	-11.144%			
Xsmall	111	111	0	0	$15.00	$3.58	$0.00	$0.00	$0.00	$6.12	($0.68)	$24.02	$4.83	25.1%
Small	330	330	0	0	$15.00	$10.65	$0.00	$0.00	$0.00	$18.18	($2.03)	$41.80	$4.46	12.0%
Medium	664	400	264	0	$15.00	$12.90	$11.16	$0.00	$0.00	$36.58	($4.08)	$71.56	$2.60	3.8%
Large	1,144	400	600	144	$15.00	$12.90	$25.35	$8.68	$0.00	$63.02	($7.02)	$117.94	$1.41	1.2%
Xlarge	2,162	400	600	1,162	$15.00	$12.90	$25.35	$70.02	$0.00	$119.11	($13.27)	$229.12	$8.75	4.0%
Mean	830	400	430	0	$15.00	$12.90	$18.15	$0.00	$0.00	$45.70	($5.09)	$86.66	$1.50	1.8%
Sum	983	400	583	0	$15.00	$12.90	$24.65	$0.00	$0.00	$54.17	($6.04)	$100.68	$0.48	0.5%
Win	669	400	269	0	$15.00	$12.90	$11.38	$0.00	$0.00	$36.88	($4.11)	$72.06	$2.58	3.7%
Annual												$1,036.45	$18.34	1.8%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

WINTER

RESIDENTIAL SERVICE DEMAND

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh				
							$15.00	$0.032258	$0.042258	$0.060258	$0.001140	$0.055090	$0.000000	
Xsm	19%	0.7	100	100	0	0	$15.00	$3.23	$0.00	$0.00	$0.11	$5.51	$0.00	$23.85
Small	24%	1.7	294	294	0	0	$15.00	$9.48	$0.00	$0.00	$0.34	$16.20	$0.00	$41.02
Medium	28%	2.8	560	400	160	0	$15.00	$12.90	$6.76	$0.00	$0.64	$30.85	$0.00	$66.15
Large	31%	4.1	914	400	514	0	$15.00	$12.90	$21.72	$0.00	$1.04	$50.35	$0.00	$101.01
XLg	35%	6.5	1,653	400	600	653	$15.00	$12.90	$25.35	$39.35	$1.88	$91.06	$0.00	$185.55
AnnAvg	30%	3.8	830	400	430	0	$15.00	$12.90	$18.15	$0.00	$0.95	$45.70	$0.00	$92.70
WinAvg	29%	3.2	669	400	269	0	$15.00	$12.90	$11.38	$0.00	$0.76	$36.88	$0.00	$76.93

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak		All kW	All kWh							
Winter				0.26	0.74	$15.00	$5.15	$0.01676	$0.000000	$0.082800	$0.038610	-11.144%			
Summer										$0.102251	$0.042830				
Xsm	19%	0.7	100	26	74	$15.00	$3.61	$1.68	$0.00	$2.15	$2.86	($0.56)	$24.74	$0.89	3.75%
Small	24%	1.7	294	76	218	$15.00	$8.76	$4.93	$0.00	$6.29	$8.42	($1.64)	$41.76	$0.74	1.79%
Medium	28%	2.8	560	145	415	$15.00	$14.42	$9.39	$0.00	$12.01	$16.02	($3.12)	$63.72	-$2.43	-3.68%
Large	31%	4.1	914	237	677	$15.00	$21.12	$15.32	$0.00	$19.62	$26.14	($5.10)	$92.10	-$8.91	-8.82%
XLg	35%	6.5	1,653	429	1,224	$15.00	$33.48	$27.70	$0.00	$35.52	$47.26	($9.22)	$149.74	-$35.81	-19.30%
AnnAvg	30%	3.8	830	215	614	$15.00	$19.57	$13.90	$0.00	$17.80	$23.71	($4.63)	$85.35	-$7.35	-7.93%
WinAvg	29%	3.2	669	174	496	$15.00	$16.48	$11.22	$0.00	$14.41	$19.15	($3.74)	$72.52	-$4.41	-5.73%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SUMMER

RESIDENTIAL SERVICE DEMAND

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh				
							$15.00	$0.032258	$0.042258	$0.060258	$0.001140	$0.055090	$0.000000	
Xsm	20%	0.8	117	117	0	0	$15.00	$3.77	$0.00	$0.00	$0.13	$6.45	$0.00	$25.35
Small	25%	2.1	386	386	0	0	$15.00	$12.45	$0.00	$0.00	$0.44	$21.26	$0.00	$49.15
Medium	30%	3.7	813	400	413	0	$15.00	$12.90	$17.45	$0.00	$0.93	$44.79	$0.00	$91.08
Large	34%	5.7	1,395	400	600	395	$15.00	$12.90	$25.35	$23.80	$1.59	$76.85	$0.00	$155.50
XLg	38%	9.0	2,471	400	600	1,471	$15.00	$12.90	$25.35	$88.64	$2.82	$136.13	$0.00	$280.85
AnnAvg	30%	3.8	830	400	430	0	$15.00	$12.90	$18.15	$0.00	$0.95	$45.70	$0.00	$92.70
SumAvg	31%	4.3	983	400	583	0	$15.00	$12.90	$24.65	$0.00	$1.12	$54.17	$0.00	$107.84

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak			All kW	All kWh							
Winter											$0.082800	$0.038610				
Summer				0.24	0.76		$15.00	$5.15	$0.01676	$0.000000	$0.102251	$0.042830	-11.144%			
Xsm	20%	0.8	117	28	89		$15.00	$4.12	$1.96	$0.00	$2.86	$3.81	($0.74)	$27.01	$1.66	6.53%
Small	25%	2.1	386	93	293		$15.00	$10.82	$6.47	$0.00	$9.51	$12.55	($2.46)	$51.89	$2.74	5.57%
Medium	30%	3.7	813	196	617		$15.00	$19.06	$13.63	$0.00	$20.04	$26.43	($5.18)	$88.98	-$2.10	-2.30%
Large	34%	5.7	1,395	336	1,059		$15.00	$29.36	$23.38	$0.00	$34.36	$45.36	($8.88)	$138.58	-$16.92	-10.88%
XLg	38%	9.0	2,471	595	1,876		$15.00	$46.35	$41.41	$0.00	$60.84	$80.35	($15.73)	$228.22	-$52.63	-18.74%
AnnAvg	30%	3.8	830	200	630		$15.00	$19.57	$13.90	$0.00	$20.45	$26.98	($5.29)	$90.61	-$2.09	-2.26%
SumAvg	31%	4.3	983	237	747		$15.00	$22.15	$16.48	$0.00	$24.23	$31.99	($6.26)	$103.59	-$4.25	-3.94%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE CARES

	BILL IMPACTS CURRENT RATES										
	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Bill	Discounts
		1-400	401+	$4.90	$0.018973	$0.035400	$0.001140	$0.061700	-$0.002139		
Xsmall	220	220	0	$4.90	$4.17	$0.00	$0.25	$13.57	-$0.47	$15.69	30.00%
Small	360	360	0	$4.90	$6.83	$0.00	$0.41	$22.21	-$0.77	$26.86	20.00%
Medium	607	400	207	$4.90	$7.59	$7.33	$0.69	$37.45	-$1.30	$50.99	10.00%
Large	990	400	590	$4.90	$7.59	$20.89	$1.13	$61.08	-$2.12	$84.12	10.00%
Xlarge	1,843	400	1,443	$4.90	$7.59	$51.08	$2.10	$113.71	-$3.94	$167.44	$8.00
Mean	753	400	353	$4.90	$7.59	$12.49	$0.86	$46.45	-$1.61	$63.61	10.00%
Sum	867	400	467	$4.90	$7.59	$16.53	$0.99	$53.49	-$1.85	$73.49	10.00%
Win	638	400	238	$4.90	$7.59	$8.43	$0.73	$39.37	-$1.37	$53.69	10.00%
Annual										$763.08	

	BILL IMPACTS PROPOSED RATES												
	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change	Discounts
		1-400	401+	$9.00	$0.030800	$0.050800	$0.000000	$0.050260	-11.144%				
Xsmall	220	220	0	$9.00	$6.78	$0.00	$0.00	$11.06	($1.23)	$17.93	$2.24	14.26%	30.00%
Small	360	360	0	$9.00	$11.09	$0.00	$0.00	$18.09	($2.02)	$28.93	$2.07	7.70%	20.00%
Medium	607	400	207	$9.00	$12.32	$10.52	$0.00	$30.51	($3.40)	$53.06	$2.07	4.05%	10.00%
Large	990	400	590	$9.00	$12.32	$29.97	$0.00	$49.76	($5.55)	$85.95	$1.83	2.18%	10.00%
Xlarge	1,843	400	1,443	$9.00	$12.32	$73.30	$0.00	$92.63	($10.32)	$168.93	$1.49	0.89%	$8.00
Mean	753	400	353	$9.00	$12.32	$17.93	$0.00	$37.84	($4.22)	$65.58	$1.97	3.10%	10.00%
Sum	867	400	467	$9.00	$12.32	$23.72	$0.00	$43.57	($4.86)	$75.38	$1.89	2.56%	10.00%
Win	638	400	238	$9.00	$12.32	$12.09	$0.00	$32.07	($3.57)	$55.72	$2.03	3.78%	10.00%
Annual										$786.56	$23.48	3.08%	

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE CARES MEDICAL

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery (kWh) 1-400	Delivery (kWh) 401+	Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Revenue	Discounts
				$4.90	$0.018973	$0.035400	$0.001140	$0.061700	-$0.002139		
Xsmall	365	365	0	$4.90	$6.93	$0.00	$0.42	$22.52	-$0.78	$23.79	30.00%
Small	564	400	164	$4.90	$7.59	$5.81	$0.64	$34.80	-$1.21	$36.77	30.00%
Medium	878	400	478	$4.90	$7.59	$16.92	$1.00	$54.17	-$1.88	$66.16	20.00%
Large	1,340	400	940	$4.90	$7.59	$33.28	$1.53	$82.68	-$2.87	$114.40	10.00%
Xlarge	2,304	400	1,904	$4.90	$7.59	$67.40	$2.63	$142.16	-$4.93	$211.75	$8.00
Mean	1,034	400	634	$4.90	$7.59	$22.43	$1.18	$63.78	-$2.21	$78.13	20.00%
sum	1,199	400	799	$4.90	$7.59	$28.28	$1.37	$73.97	-$2.56	$90.84	20.00%
win	871	400	471	$4.90	$7.59	$16.68	$0.99	$53.75	-$1.86	$65.64	20.00%
Annual										$938.88	

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh) 1-400	Delivery (kWh) 401+	Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Revenue	$ Change	% Change	Discounts
				$9.00	$0.030800	$0.050800	$0.000000	$0.050260	-11.144%				
Xsmall	365	365	0	$9.00	$11.24	$0.00	$0.00	$18.34	($2.04)	$25.58	$1.79	7.5%	30.00%
Small	564	400	164	$9.00	$12.32	$8.33	$0.00	$28.35	($3.16)	$38.39	$1.62	4.4%	30.00%
Medium	878	400	478	$9.00	$12.32	$24.28	$0.00	$44.13	($4.92)	$67.85	$1.69	2.6%	20.00%
Large	1,340	400	940	$9.00	$12.32	$47.75	$0.00	$67.35	($7.51)	$128.81	$14.41	12.6%	10.00%
Xlarge	2,304	400	1,904	$9.00	$12.32	$96.72	$0.00	$115.80	($12.90)	$212.94	$1.19	0.6%	$8.00
Mean	1,034	400	634	$9.00	$12.32	$32.19	$0.00	$51.95	($5.79)	$79.74	$1.61	2.1%	20.00%
sum	1,199	400	799	$9.00	$12.32	$40.58	$0.00	$60.25	($6.71)	$92.35	$1.51	1.7%	20.00%
win	871	400	471	$9.00	$12.32	$23.93	$0.00	$43.78	($4.88)	$67.32	$1.68	2.6%	20.00%
Annual										$958.03	$19.15	2.0%	

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

WINTER

RESIDENTIAL SERVICE DEMAND - CARES

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh					
							$9.00	$0.030800	$0.050800	$0.050800	$0.000000	$0.050260	$0.000000		
Xsm	22%	1.2	198	198	0	0	$9.00	$6.10	$0.00	$0.00	$0.00	$9.95	$0.00	$17.53	30.00%
Small	25%	1.8	324	324	0	0	$9.00	$9.98	$0.00	$0.00	$0.00	$16.28	$0.00	$28.21	20.00%
Medium	27%	2.7	525	400	125	0	$9.00	$12.32	$6.35	$0.00	$0.00	$26.39	$0.00	$48.65	10.00%
Large	30%	3.8	831	400	431	0	$9.00	$12.32	$21.89	$0.00	$0.00	$41.77	$0.00	$76.49	10.00%
XLg	34%	6.0	1,496	400	600	496	$9.00	$12.32	$30.48	$25.20	$0.00	$75.19	$0.00	$144.19	$8.00
AnnAvg	30%	3.9	867	400	467	0	$9.00	$12.32	$23.72	$0.00	$0.00	$43.57	$0.00	$79.75	10.00%
WinAvg	28%	3.1	638	400	238	0	$9.00	$12.32	$12.09	$0.00	$0.00	$32.07	$0.00	$58.94	10.00%

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	Discounts
				On-Peak	Off-Peak		All kW	All kWh								
						15.00	5.15	$0.01676	$0.000000							
Winter				0.26	0.74					$0.082800	$0.038610	-11.144%				
Summer										$0.102251	$0.042830					
Xsm	22%	1.2	198	51	147	$15.00	$6.18	$3.32	$0.00	$4.22	$5.68	($1.10)	$27.31	$9.78	55.8%	18.00%
Small	25%	1.8	324	84	240	$15.00	$9.27	$5.43	$0.00	$6.96	$9.27	($1.81)	$36.18	$7.97	28.3%	18.00%
Medium	27%	2.7	525	136	389	$15.00	$13.91	$8.80	$0.00	$11.26	$15.02	($2.93)	$50.07	$1.42	2.9%	18.00%
Large	30%	3.8	831	216	615	$15.00	$19.57	$13.93	$0.00	$17.88	$23.75	($4.64)	$70.10	-$6.39	-8.4%	18.00%
XLg	34%	6.0	1,496	388	1,108	$15.00	$30.90	$25.07	$0.00	$32.13	$42.78	($8.35)	$121.53	-$22.66	-15.7%	$16.00
AnnAvg	30%	3.9	867	225	642	$15.00	$20.09	$14.53	$0.00	$18.63	$24.79	($4.84)	$72.32	-$7.43	-9.3%	18.00%
WinAvg	28%	3.1	638	166	472	$15.00	$15.97	$10.69	$0.00	$13.74	$18.22	($3.56)	$57.45	-$1.49	-2.5%	18.00%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SUMMER

RESIDENTIAL SERVICE DEMAND - CARES

	BILL IMPACTS PROPOSED TRANSITION RATES														
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh					
							$9.00	$0.030800	$0.050800	$0.050800	$0.000000	$0.050260	$0.000000		
Xsm	23%	1.4	243	243	0	0	$9.00	$7.48	$0.00	$0.00	$0.00	$12.21	$0.00	$20.09	30.00%
Small	26%	2.2	413	400	13	0	$9.00	$12.32	$0.66	$0.00	$0.00	$20.76	$0.00	$34.19	20.00%
Medium	29%	3.4	709	400	309	0	$9.00	$12.32	$15.70	$0.00	$0.00	$35.63	$0.00	$65.38	10.00%
Large	32%	4.9	1,161	400	600	161	$9.00	$12.32	$30.48	$8.18	$0.00	$58.35	$0.00	$110.33	$8.00
XLg	37%	7.8	2,078	400	600	1,078	$9.00	$12.32	$30.48	$54.76	$0.00	$104.44	$0.00	$203.00	$8.00
AnnAvg	30%	3.9	867	400	467	0	$9.00	$12.32	$23.72	$0.00	$0.00	$43.57	$0.00	$79.75	10.00%
SumAvg	30%	3.9	863	400	463	0	$9.00	$12.32	$23.54	$0.00	$0.00	$43.39	$0.00	$79.43	10.00%

	BILL IMPACTS PROPOSED RATES															
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
				On-Peak	Off-Peak		All kW	All kWh								
Winter										$0.082800	$0.038610					
Summer				0.24	0.76	$15.00	$5.15	$0.01676	$0.000000	$0.102251	$0.042830	-11.144%				
Xsm	23%	1.4	243	58	185	$15.00	$7.21	$4.07	$0.00	$5.93	$7.92	($1.54)	$31.64	$11.55	57.5%	18.00%
Small	26%	2.2	413	99	314	$15.00	$11.33	$6.92	$0.00	$10.12	$13.45	($2.63)	$44.44	$10.25	30.0%	18.00%
Medium	29%	3.4	709	171	538	$15.00	$17.51	$11.88	$0.00	$17.48	$23.04	($4.52)	$65.92	$0.54	0.8%	18.00%
Large	32%	4.9	1,161	279	882	$15.00	$25.24	$19.46	$0.00	$28.53	$37.78	($7.39)	$102.62	-$7.71	-7.0%	$16.00
XLg	37%	7.8	2,078	500	1,578	$15.00	$40.17	$34.83	$0.00	$51.13	$67.59	($13.23)	$179.49	-$23.51	-11.6%	$16.00
AnnAvg	30%	3.9	867	209	658	$15.00	$20.09	$14.53	$0.00	$21.37	$28.18	($5.52)	$76.79	-$2.96	-3.7%	18.00%
SumAvg	30%	3.9	863	208	656	$15.00	$20.09	$14.47	$0.00	$21.27	$28.10	($5.50)	$76.61	-$2.82	-3.6%	18.00%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND - CARES MEDICAL

WINTER

	BILL IMPACTS PROPOSED TRANSITION RATES														
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh					
							$9.00	$0.030800	$0.050800	$0.050800	$0.000000	$0.050260	$0.000000		
Xsm	24%	1.8	323	323	0	0	$9.00	$9.95	$0.00	$0.00	$0.00	$16.23	$0.00	$24.62	30.00%
Small	27%	2.5	495	400	95	0	$9.00	$12.32	$4.83	$0.00	$0.00	$24.88	$0.00	$35.72	30.00%
Medium	29%	3.6	763	400	363	0	$9.00	$12.32	$18.44	$0.00	$0.00	$38.35	$0.00	$62.49	20.00%
Large	32%	4.8	1,115	400	600	115	$9.00	$12.32	$30.48	$5.84	$0.00	$56.04	$0.00	$90.95	20.00%
XLg	36%	7.2	1,887	400	600	887	$9.00	$12.32	$30.48	$45.06	$0.00	$94.84	$0.00	$172.53	10.00%
AnnAvg	32%	5.1	1,199	400	600	199	$9.00	$12.32	$30.48	$10.10	$0.00	$60.25	$0.00	$97.72	20.00%
WinAvg	30%	4.0	871	400	471	0	$9.00	$12.32	$23.93	$0.00	$0.00	$43.78	$0.00	$71.23	20.00%

	BILL IMPACTS PROPOSED RATES															
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
				On-Peak	Off-Peak		All kW	All kWh								
						15.00	5.15	$0.01676	$0.000000							
Winter				0.26	0.74											
Summer										$0.082800	$0.038610	-11.144%				
										$0.102251	$0.042830					
Xsm	24%	1.8	323	84	239	$15.00	$9.27	$5.41	$0.00	$6.96	$9.23	($1.80)	$33.49	$8.87	36.0%	24.00%
Small	27%	2.5	495	128	367	$15.00	$12.88	$8.30	$0.00	$10.60	$14.17	($2.76)	$44.22	$8.50	23.8%	24.00%
Medium	29%	3.6	763	198	565	$15.00	$18.54	$12.79	$0.00	$16.39	$21.81	($4.26)	$61.01	-$1.48	-2.4%	24.00%
Large	32%	4.8	1,115	289	826	$15.00	$24.72	$18.69	$0.00	$23.93	$31.89	($6.22)	$82.09	-$8.86	-9.7%	24.00%
XLg	36%	7.2	1,887	490	1,397	$15.00	$37.08	$31.63	$0.00	$40.57	$53.94	($10.53)	$127.44	-$45.09	-26.1%	24.00%
AnnAvg	32%	5.1	1,199	311	888	$15.00	$26.27	$20.09	$0.00	$25.75	$34.29	($6.69)	$87.18	-$10.54	-10.8%	24.00%
WinAvg	30%	4.0	871	226	645	$15.00	$20.60	$14.60	$0.00	$18.71	$24.90	($4.86)	$67.60	-$3.63	-5.1%	24.00%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND - CARES MEDICAL

SUMMER

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+	$9.00	0-400 kWh $0.030800	401-1,000 kWh $0.050800	1,000+ kWh $0.050800	$0.000000	$0.050260	$0.000000		
Xsm	26%	2.2	414	400	14	0	$9.00	$12.32	$0.71	$0.00	$0.00	$20.81	$0.00	$29.99	30.00%
Small	29%	3.2	663	400	263	0	$9.00	$12.32	$13.34	$0.00	$0.00	$33.30	$0.00	$54.36	20.00%
Medium	31%	4.5	1,035	400	600	35	$9.00	$12.32	$30.48	$1.78	$0.00	$52.02	$0.00	$84.48	20.00%
Large	34%	6.3	1,572	400	600	572	$9.00	$12.32	$30.48	$29.03	$0.00	$78.98	$0.00	$143.83	10.00%
XLg	38%	9.3	2,601	400	600	1,601	$9.00	$12.32	$30.48	$81.33	$0.00	$130.73	$0.00	$255.86	$8.00
AnnAvg	32%	5.1	1,199	400	600	199	$9.00	$12.32	$30.48	$10.10	$0.00	$60.25	$0.00	$97.72	20.00%
SumAvg	32%	5.0	1,194	400	600	194	$9.00	$12.32	$30.48	$9.84	$0.00	$60.00	$0.00	$97.32	20.00%

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh) On-Peak	Delivery (kWh) Off-Peak	Basic Service Charge	Delivery All kW	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
Winter										$0.082800	$0.038610					
Summer				0.24	0.76	$15.00	$5.15	$0.01676	$0.000000	$0.102251	$0.042830	-11.144%				
Xsm	26%	2.2	414	100	314	$15.00	$11.33	$6.94	$0.00	$10.23	$13.45	($2.64)	$41.28	$11.29	37.6%	24.00%
Small	29%	3.2	663	159	503	$15.00	$16.48	$11.10	$0.00	$16.26	$21.54	($4.21)	$57.89	$3.53	6.5%	24.00%
Medium	31%	4.5	1,035	249	786	$15.00	$23.18	$17.35	$0.00	$25.46	$33.66	($6.59)	$82.13	-$2.35	-2.8%	24.00%
Large	34%	6.3	1,572	378	1,193	$15.00	$32.45	$26.34	$0.00	$38.65	$51.10	($10.00)	$116.69	-$27.14	-18.9%	24.00%
XLg	38%	9.3	2,601	626	1,975	$15.00	$47.90	$43.59	$0.00	$64.01	$84.59	($16.56)	$222.53	-$33.33	-13.0%	$16.00
AnnAvg	32%	5.1	1,199	288	910	$15.00	$26.27	$20.09	$0.00	$29.45	$38.98	($7.63)	$92.84	-$4.88	-5.0%	24.00%
SumAvg	32%	5.0	1,194	287	907	$15.00	$25.75	$20.01	$0.00	$29.35	$38.85	($7.60)	$92.23	-$5.09	-5.2%	24.00%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+							
	Winter	0.24	0.76				$11.50	$0.030350	$0.001140	$0.129605	$0.031385	-$0.002139	
	Summer									$0.129605	$0.039605		
Xsm	150	36	114	150	0	0	$11.50	$4.55	$0.17	$4.67	$3.58	-$0.32	$24.15
Small	286	69	217	286	0	0	$11.50	$8.68	$0.33	$8.90	$6.82	-$0.61	$35.62
Medium	641	154	487	400	241	0	$11.50	$19.45	$0.73	$19.94	$15.29	-$1.37	$65.54
Large	1,043	250	793	400	600	43	$11.50	$31.66	$1.19	$32.44	$24.88	-$2.23	$99.44
XLg	1,810	434	1,376	400	600	810	$11.50	$54.93	$2.06	$56.30	$43.17	-$3.87	$164.09
AnnAvg	1,008	242	766	400	600	8	$11.50	$30.59	$1.15	$31.36	$24.05	-$2.16	$96.49
Avg Win	801	192	608	400	401	0	$11.50	$24.30	$0.91	$24.90	$19.10	-$1.71	$79.00

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+							
	Winter						$15.00	$0.036900	$0.036900	$0.036900	$0.000000	$0.091550	$0.038610	-11.144%			
	Summer											$0.111001	$0.042830			$ Change	% Change
Xsm	150	36	114	150	0	0	$15.00	$5.54	$0.00	$0.00	$0.00	$3.30	$4.40	($0.86)	$27.38	$3.23	13.37%
Small	286	69	217	286	0	0	$15.00	$10.55	$0.00	$0.00	$0.00	$6.28	$8.39	($1.63)	$38.59	$2.97	8.34%
Medium	641	154	487	400	241	0	$15.00	$14.76	$8.89	$0.00	$0.00	$14.08	$18.81	($3.67)	$67.87	$2.33	3.56%
Large	1,043	250	793	400	600	43	$15.00	$14.76	$22.14	$1.59	$0.00	$22.92	$30.61	($5.97)	$101.05	$1.61	1.62%
XLg	1,810	434	1,376	400	600	810	$15.00	$14.76	$22.14	$29.89	$0.00	$39.77	$53.11	($10.35)	$164.32	$0.23	0.14%
AnnAvg	1,008	242	766	400	600	8	$15.00	$14.76	$22.14	$0.30	$0.00	$22.15	$29.58	($5.76)	$98.17	$1.68	1.74%
Avg Win	801	192	608	400	401	0	$15.00	$14.76	$14.78	$0.00	$0.00	$17.59	$23.49	($4.58)	$81.04	$2.04	2.58%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+							
	Winter						$11.50	$0.030350	$0.001140	$0.129605	$0.031385	-$0.002139	
	Summer	0.23	0.77							$0.129605	$0.039605		
Xsm	261	60	201	261	0	0	$11.50	$7.92	$0.30	$7.78	$7.96	-$0.56	$34.90
Small	525	121	404	400	125	0	$11.50	$15.93	$0.60	$15.65	$16.01	-$1.12	$58.57
Medium	983	226	757	400	583	0	$11.50	$29.83	$1.12	$29.30	$29.98	-$2.10	$99.63
Large	1,611	371	1,240	400	600	611	$11.50	$48.89	$1.84	$48.02	$49.13	-$3.45	$155.93
XLg	2,681	617	2,064	400	600	1,681	$11.50	$81.37	$3.06	$79.92	$81.76	-$5.74	$251.87
AnnAvg	1,008	232	776	400	600	8	$11.50	$30.59	$1.15	$30.05	$30.74	-$2.16	$101.87
Avg Sum	1,195	275	920	400	600	195	$11.50	$36.26	$1.36	$35.61	$36.43	-$2.56	$118.60

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+							
	Winter						$15.00	$0.036900	$0.036900	$0.036900	$0.000000	$0.091550	$0.038610				
	Summer											$0.111001	$0.042830	-11.144%			
Xsm	261	60	201	261	0	0	$15.00	$9.63	$0.00	$0.00	$0.00	$6.66	$8.61	($1.70)	$38.20	$3.30	9.45%
Small	525	121	404	400	125	0	$15.00	$14.76	$4.61	$0.00	$0.00	$13.40	$17.31	($3.42)	$61.66	$3.09	5.28%
Medium	983	226	757	400	583	0	$15.00	$14.76	$21.51	$0.00	$0.00	$25.10	$32.42	($6.41)	$102.38	$2.75	2.76%
Large	1,611	371	1,240	400	600	611	$15.00	$14.76	$22.14	$22.55	$0.00	$41.13	$53.13	($10.50)	$158.21	$2.28	1.46%
XLg	2,681	617	2,064	400	600	1,681	$15.00	$14.76	$22.14	$62.03	$0.00	$68.45	$88.42	($17.48)	$253.32	$1.45	0.57%
AnnAvg	1,008	232	776	400	600	8	$15.00	$14.76	$22.14	$0.30	$0.00	$25.74	$33.25	($6.57)	$104.62	$2.75	2.70%
Avg Sum	1,195	275	920	400	600	195	$15.00	$14.76	$22.14	$7.19	$0.00	$30.50	$39.40	($7.79)	$121.20	$2.60	2.19%

	Net Bill	$ Change	% Change
Current Annual	$1,185.62		
Proposed Annual	$1,213.44	$27.82	2.35%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE DEMAND

WINTER

BILL IMPACTS PROPOSED TRANSITION RATES - RES TOU

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
	Winter	0.24	0.76				$15.00	$0.036900	$0.036900	$0.036900	$0.000000	$0.091550	$0.038610	0.000%	
	Summer											$0.111001	$0.042830		
Xsm	150	36	114	150	0	0	$15.00	$5.54	$0.00	$0.00	$0.00	$3.30	$4.40	$0.00	$28.24
Small	286	69	217	286	0	0	$15.00	$10.55	$0.00	$0.00	$0.00	$6.28	$8.39	$0.00	$40.22
Medium	641	154	487	400	241	0	$15.00	$14.76	$8.89	$0.00	$0.00	$14.08	$18.81	$0.00	$71.54
Large	1,043	250	793	400	600	43	$15.00	$14.76	$22.14	$1.59	$0.00	$22.92	$30.61	$0.00	$107.02
XLg	1,810	434	1,376	400	600	810	$15.00	$14.76	$22.14	$29.89	$0.00	$39.77	$53.11	$0.00	$174.67
AnnAvg	1,008	242	766	400	600	8	$15.00	$14.76	$22.14	$0.30	$0.00	$22.15	$29.58	$0.00	$103.93
Avg Win	801	192	608	400	401	0	$15.00	$14.76	$14.78	$0.00	$0.00	$17.59	$23.49	$0.00	$85.62

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak					All kW	All kWh							
Winter		0.24	0.76				$15.00	$5.15	$0.01676	$0.000000	$0.082800	$0.038610	-11.144%			
Summer											$0.102251	$0.042830				
Xsm	150	36	114	21%	1.0		$15.00	$5.15	$2.51	$0.00	$2.98	$4.40	($0.82)	$29.22	$0.98	3.47%
Small	286	69	217	24%	1.6		$15.00	$8.24	$4.79	$0.00	$5.68	$8.39	($1.57)	$40.53	$0.31	0.77%
Medium	641	154	487	28%	3.1		$15.00	$15.97	$10.74	$0.00	$12.74	$18.81	($3.52)	$69.74	-$1.80	-2.52%
Large	1,043	250	793	31%	4.5		$15.00	$23.18	$17.48	$0.00	$20.73	$30.61	($5.72)	$101.28	-$5.74	-5.36%
XLg	1,810	434	1,376	35%	7.0		$15.00	$36.05	$30.34	$0.00	$35.97	$53.11	($9.93)	$160.54	-$14.13	-8.09%
AnnAvg	1,008	242	766	31%	4.4		$15.00	$22.66	$16.90	$0.00	$20.03	$29.58	($5.53)	$98.64	-$5.29	-5.09%
WinAvg	801	192	608	30%	3.7		$15.00	$19.06	$13.42	$0.00	$15.91	$23.49	($4.39)	$82.49	-$3.13	-3.66%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE DEMAND

SUMMER

BILL IMPACTS PROPOSED TRANSITION RATES - RES TOU

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
	Winter						$15.00	$0.036900	$0.036900	$0.036900	$0.000000	$0.091550	$0.038610		
	Summer	0.23	0.77									$0.111001	$0.042830	0.000%	
Xsm	261	60	201	261	0	0	$15.00	$9.63	$0.00	$0.00	$0.00	$6.66	$8.61	$0.00	$39.90
Small	525	121	404	400	125	0	$15.00	$14.76	$4.61	$0.00	$0.00	$13.40	$17.31	$0.00	$65.08
Medium	983	226	757	400	583	0	$15.00	$14.76	$21.51	$0.00	$0.00	$25.10	$32.42	$0.00	$108.79
Large	1,611	371	1,240	400	600	611	$15.00	$14.76	$22.14	$22.55	$0.00	$41.13	$53.13	$0.00	$168.71
XLg	2,681	617	2,064	400	600	1,681	$15.00	$14.76	$22.14	$62.03	$0.00	$68.45	$88.42	$0.00	$270.80
AnnAvg	1,008	232	776	400	600	8	$15.00	$14.76	$22.14	$0.30	$0.00	$25.74	$33.25	$0.00	$111.19
Avg Win	1,195	275	920	400	600	195	$15.00	$14.76	$22.14	$7.19	$0.00	$30.50	$39.40	$0.00	$128.99

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak					All kW	All kWh							
Winter							$15.00	$5.15	$0.01676	$0.000000	$0.082800	$0.038610				
Summer		0.23	0.77								$0.102251	$0.042830	-11.144%			
Xsm	261	60	201	23%	1.5		$15.00	$7.73	$4.37	$0.00	$6.14	$8.61	($1.64)	$40.21	$0.31	0.78%
Small	525	121	404	27%	2.7		$15.00	$13.91	$8.80	$0.00	$12.37	$17.30	($3.31)	$64.07	-$1.01	-1.55%
Medium	983	226	757	31%	4.3		$15.00	$22.15	$16.48	$0.00	$23.11	$32.42	($6.19)	$102.97	-$5.82	-5.35%
Large	1,611	371	1,240	35%	6.4		$15.00	$32.96	$27.00	$0.00	$37.94	$53.11	($10.15)	$155.86	-$12.85	-7.62%
XLg	2,681	617	2,064	39%	9.5		$15.00	$48.93	$44.93	$0.00	$63.09	$88.40	($16.88)	$243.47	-$27.33	-10.09%
AnnAvg	1,008	232	776	31%	4.4		$15.00	$22.66	$16.90	$0.00	$23.72	$33.24	($6.35)	$105.17	-$6.02	-5.41%
WinAvg	1,195	275	920	32%	5.1		$15.00	$26.27	$20.02	$0.00	$28.12	$39.40	($7.52)	$121.29	-$7.70	-5.97%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE - SUPER PEAK

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
	Winter	0.1	0.9				$11.50	$0.025000	$0.035000	$0.035000	$0.001140	$0.150000	$0.038700	-$0.002139	
	Summer											$0.170000	$0.039700		
Xsm	150	15	135	150	0	0	$11.50	$3.75	$0.00	$0.00	$0.17	$2.25	$5.22	-$0.32	$22.57
Small	286	29	257	286	0	0	$11.50	$7.15	$0.00	$0.00	$0.33	$4.29	$9.96	-$0.61	$32.62
Medium	641	64	577	400	241	0	$11.50	$10.00	$8.44	$0.00	$0.73	$9.62	$22.33	-$1.37	$61.25
Large	1,043	104	939	400	600	43	$11.50	$10.00	$21.00	$1.51	$1.19	$15.65	$36.33	-$2.23	$94.95
XLg	1,810	181	1,629	400	600	810	$11.50	$10.00	$21.00	$28.35	$2.06	$27.15	$63.04	-$3.87	$159.23
AnnAvg	1,008	101	907	400	600	8	$11.50	$10.00	$21.00	$0.28	$1.15	$15.12	$35.11	-$2.16	$92.00
Avg Win	801	80	721	400	401	0	$11.50	$10.00	$14.02	$0.00	$0.91	$12.01	$27.89	-$1.71	$74.62

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+							
	Winter						$15.00	$0.032258	$0.035500	$0.035500	$0.000000	$0.159790	$0.040810	-11.144%			
	Summer											$0.159790	$0.040810				
Xsm	150	15	135	150	0	0	$15.00	$4.84	$0.00	$0.00	$0.00	$2.40	$5.51	($0.88)	$26.87	$4.30	19.05%
Small	286	29	257	286	0	0	$15.00	$9.23	$0.00	$0.00	$0.00	$4.57	$10.50	($1.68)	$37.62	$5.00	15.33%
Medium	641	64	577	400	241	0	$15.00	$12.90	$8.56	$0.00	$0.00	$10.24	$23.54	($3.76)	$66.48	$5.23	8.54%
Large	1,043	104	939	400	600	43	$15.00	$12.90	$21.30	$1.53	$0.00	$16.67	$38.31	($6.13)	$99.58	$4.63	4.88%
XLg	1,810	181	1,629	400	600	810	$15.00	$12.90	$21.30	$28.76	$0.00	$28.92	$66.48	($10.63)	$162.73	$3.50	2.20%
AnnAvg	1,008	101	907	400	600	8	$15.00	$12.90	$21.30	$0.29	$0.00	$16.11	$37.03	($5.92)	$96.71	$4.71	5.12%
AvgWin	801	80	721	400	401	0	$15.00	$12.90	$14.22	$0.00	$0.00	$12.79	$29.41	($4.70)	$79.62	$5.00	6.70%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE - SUPER PEAK

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
	Winter						$11.50	$0.025000	$0.035000	$0.035000	$0.001140	$0.150000	$0.038700	-$0.002139	
	Summer	0.14	0.86									$0.170000	$0.039700		
Xsm	261	37	224	261	0	0	$11.50	$6.53	$0.00	$0.00	$0.30	$6.21	$8.91	-$0.56	$32.89
Small	525	74	452	400	125	0	$11.50	$10.00	$4.38	$0.00	$0.60	$12.50	$17.92	-$1.12	$55.78
Medium	983	138	845	400	583	0	$11.50	$10.00	$20.41	$0.00	$1.12	$23.40	$33.56	-$2.10	$97.89
Large	1,611	226	1,385	400	600	611	$11.50	$10.00	$21.00	$21.39	$1.84	$38.34	$55.00	-$3.45	$155.62
XLg	2,681	375	2,306	400	600	1,681	$11.50	$10.00	$21.00	$58.84	$3.06	$63.81	$91.53	-$5.74	$254.00
AnnAvg	1,008	141	867	400	600	8	$11.50	$10.00	$21.00	$0.28	$1.15	$23.99	$34.42	-$2.16	$100.18
AvgSum	1,195	167	1,027	400	600	195	$11.50	$10.00	$21.00	$6.82	$1.36	$28.43	$40.79	-$2.56	$117.34

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak	0-400	401-1,000	1,000+	$15.00	0-400	401-1,000	1,000+							
	Winter							$0.032258	$0.035500	$0.035500	$0.000000	$0.159790	$0.040810				
	Summer	0.14	0.86									$0.159790	$0.040810	-11.144%			
Xsm	261	37	224	261	0	0	$15.00	$8.42	$0.00	$0.00	$0.00	$5.84	$9.16	($1.67)	$36.75	$3.86	11.73%
Small	525	74	452	400	125	0	$15.00	$12.90	$4.44	$0.00	$0.00	$11.74	$18.43	($3.36)	$59.15	$3.37	6.05%
Medium	983	138	845	400	583	0	$15.00	$12.90	$20.70	$0.00	$0.00	$21.99	$34.50	($6.30)	$98.79	$0.90	0.92%
Large	1,611	226	1,385	400	600	611	$15.00	$12.90	$21.30	$21.69	$0.00	$36.04	$56.54	($10.32)	$153.15	($2.47)	-1.59%
XLg	2,681	375	2,306	400	600	1,681	$15.00	$12.90	$21.30	$59.68	$0.00	$59.98	$94.09	($17.17)	$245.78	($8.22)	-3.24%
AnnAvg	1,008	141	867	400	600	8	$15.00	$12.90	$21.30	$0.29	$0.00	$22.55	$35.38	($6.46)	$100.96	$0.78	0.78%
AvgSum	1,195	167	1,027	400	600	195	$15.00	$12.90	$21.30	$6.91	$0.00	$26.73	$41.93	($7.65)	$117.12	($0.22)	-0.19%

	Net Bill	$ Change	% Change
Current Annual	$1,151.78		
Proposed Annual	$1,180.44	$28.66	2.49%

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

SMALL GENERAL SERVICE

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery kWh			Basic Service Charge	Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill
		1-400	401-7500	7501+		1-400	401-7500	7501+				
					$14.50	$0.030176	$0.041042	$0.076042	$0.001140	$0.058241	-$0.002139	
Xsm	200	200	0	0	$14.50	$6.04	$0.00	$0.00	$0.23	$11.65	-$0.43	$31.99
Small	350	350	0	0	$14.50	$10.56	$0.00	$0.00	$0.40	$20.38	-$0.75	$45.09
Medium	561	400	161	0	$14.50	$12.07	$6.61	$0.00	$0.64	$32.67	-$1.20	$65.29
Large	1,447	400	1,047	0	$14.50	$12.07	$42.97	$0.00	$1.65	$84.27	-$3.10	$152.36
XLg	4,078	400	3,678	0	$14.50	$12.07	$150.95	$0.00	$4.65	$237.51	-$8.72	$410.96
Mean	1,131	400	731	0	$14.50	$12.07	$30.00	$0.00	$1.29	$65.87	-$2.42	$121.31
sum	1,277	400	877	0	$14.50	$12.07	$36.00	$0.00	$1.46	$74.39	-$2.73	$135.69
win	980	400	580	0	$14.50	$12.07	$23.82	$0.00	$1.12	$57.10	-$2.10	$106.51
Annual												$1,453.20

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery kWh			Basic Service Charge	Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		1-400	401-7500	7501+		1-400	401-7500	7501+						
					$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.053290	-11.144%			
Xsm	200	200	0	0	$30.00	$6.48	$0.00	$0.00	$0.00	$10.66	($1.19)	$45.95	$13.96	43.63%
Small	350	350	0	0	$30.00	$11.34	$0.00	$0.00	$0.00	$18.65	($2.08)	$57.91	$12.82	28.43%
Medium	561	400	161	0	$30.00	$12.96	$6.83	$0.00	$0.00	$29.90	($3.33)	$76.36	$11.07	16.96%
Large	1,447	400	1,047	0	$30.00	$12.96	$44.39	$0.00	$0.00	$77.11	($8.59)	$155.87	$3.51	2.30%
XLg	4,078	400	3,678	0	$30.00	$12.96	$155.95	$0.00	$0.00	$217.32	($24.22)	$392.01	-$18.95	-4.61%
Mean	1,131	400	731	0	$30.00	$12.96	$30.99	$0.00	$0.00	$60.27	($6.72)	$127.50	$6.19	5.10%
sum	1,277	400	877	0	$30.00	$12.96	$37.20	$0.00	$0.00	$68.07	($7.59)	$140.64	$4.95	3.65%
win	980	400	580	0	$30.00	$12.96	$24.61	$0.00	$0.00	$52.25	($5.82)	$114.00	$7.49	7.03%
Annual												$1,527.84	$74.64	5.14%

WINTER

SMALL GENERAL SERVICE DEMAND

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery kWh			Basic Service Charge	Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill
				1-400	401-7500	7501+		1-400	401-7500	7501+				
							$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.053290	$0.000000	
Xsm	27%	0.9	173	173	0	0	$30.00	$5.61	$0.00	$0.00	$0.00	$9.22	$0.00	$44.82
Small	30%	1.4	303	303	0	0	$30.00	$9.82	$0.00	$0.00	$0.00	$16.15	$0.00	$55.96
Medium	33%	2.0	486	400	86	0	$30.00	$12.96	$3.65	$0.00	$0.00	$25.90	$0.00	$72.51
Large	40%	4.3	1,254	400	854	0	$30.00	$12.96	$36.21	$0.00	$0.00	$66.83	$0.00	$146.00
XLg	48%	10.1	3,535	400	3,135	0	$30.00	$12.96	$132.92	$0.00	$0.00	$188.38	$0.00	$364.26
AnnAvg	39%	4.0	1,131	400	731	0	$30.00	$12.96	$30.99	$0.00	$0.00	$60.27	$0.00	$134.22
WinAvg	38%	3.6	980	400	580	0	$30.00	$12.96	$24.61	$0.00	$0.00	$52.25	$0.00	$119.82

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak		All kW	All kWh		On-Peak	Off-Peak				
						30.00	5.49	$0.016680	$0.000000						
	Winter			0.30	0.70					$0.083570	$0.040036	-11.144%			
	Summer									$0.084570	$0.045800				
Xsm	27%	0.9	173	53	120	$30.00	$4.94	$2.89	$0.00	$4.39	$4.82	($1.03)	$46.01	$1.19	2.65%
Small	30%	1.4	303	92	211	$30.00	$7.69	$5.05	$0.00	$7.70	$8.44	($1.80)	$57.08	$1.12	1.99%
Medium	33%	2.0	486	148	338	$30.00	$10.98	$8.11	$0.00	$12.35	$13.54	($2.89)	$72.09	-$0.42	-0.57%
Large	40%	4.3	1,254	381	873	$30.00	$23.61	$20.92	$0.00	$31.86	$34.94	($7.44)	$133.89	-$12.11	-8.29%
XLg	48%	10.1	3,535	1,075	2,460	$30.00	$55.45	$58.96	$0.00	$89.80	$98.50	($20.98)	$311.73	-$52.53	-14.42%
AnnAvg	39%	4.0	1,131	344	787	$30.00	$21.96	$18.86	$0.00	$28.73	$31.52	($6.71)	$124.36	-$9.86	-7.35%
WinAvg	38%	3.6	980	298	682	$30.00	$19.76	$16.35	$0.00	$24.91	$27.32	($5.82)	$112.52	-$7.30	-6.09%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SUMMER

SMALL GENERAL SERVICE DEMAND

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Total kWh	Delivery kWh 1-400	Delivery kWh 401-7500	Delivery kWh 7501+	Basic Service Charge	Delivery (kWh) 1-400	Delivery (kWh) 401-7500	Delivery (kWh) 7501+	TCA	Base Fuel	PPFAC	Net Bill
							$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.053290	$0.000000	
Xsm	29%	1.1	226	226	0	0	$30.00	$7.32	$0.00	$0.00	$0.00	$12.04	$0.00	$49.37
Small	32%	1.7	395	395	0	0	$30.00	$12.80	$0.00	$0.00	$0.00	$21.05	$0.00	$63.85
Medium	35%	2.5	634	400	234	0	$30.00	$12.96	$9.92	$0.00	$0.00	$33.79	$0.00	$86.67
Large	42%	5.4	1,634	400	1,234	0	$30.00	$12.96	$52.32	$0.00	$0.00	$87.08	$0.00	$182.36
XLg	51%	12.5	4,605	400	4,205	0	$30.00	$12.96	$178.29	$0.00	$0.00	$245.40	$0.00	$466.65
AnnAvg	39%	4.0	1,131	400	731	0	$30.00	$12.96	$30.99	$0.00	$0.00	$60.27	$0.00	$134.22
SumAvg	40%	4.4	1,277	400	877	0	$30.00	$12.96	$37.20	$0.00	$0.00	$68.07	$0.00	$148.22

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh) On-Peak	Delivery (kWh) Off-Peak	Basic Service Charge	Delivery All kW	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
	Winter					30.00	5.49	$0.016680	$0.000000						
	Summer			0.27	0.73					$0.083570	$0.040036				
										$0.084570	$0.045800	-11.144%			
Xsm	29%	1.1	226	60	166	$30.00	$6.04	$3.77	$0.00	$5.07	$7.61	($1.41)	$51.08	$1.71	3.47%
Small	32%	1.7	395	105	290	$30.00	$9.33	$6.59	$0.00	$8.85	$13.30	($2.47)	$65.60	$1.75	2.74%
Medium	35%	2.5	634	168	466	$30.00	$13.73	$10.58	$0.00	$14.21	$21.34	($3.96)	$85.90	-$0.77	-0.89%
Large	42%	5.4	1,634	433	1,201	$30.00	$29.65	$27.26	$0.00	$36.62	$55.00	($10.21)	$168.32	-$14.04	-7.70%
XLg	51%	12.5	4,605	1,220	3,385	$30.00	$68.63	$76.81	$0.00	$103.21	$155.01	($28.78)	$404.88	-$61.77	-13.24%
AnnAvg	39%	4.0	1,131	300	831	$30.00	$21.96	$18.86	$0.00	$25.35	$38.07	($7.07)	$127.17	-$7.05	-5.26%
SumAvg	40%	4.4	1,277	339	939	$30.00	$24.16	$21.30	$0.00	$28.63	$43.00	($7.98)	$139.11	-$9.11	-6.15%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

Exhibit CAJ-R-5

Schedule H-4-FC-R

SMALL GENERAL SERVICE RATE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23					$16.50	$0.030176	$0.043176	$0.076042	$0.001140	$0.129605	$0.031385	-$0.002139	
	Summer	0.18										$0.129605	$0.039605		
Xsm	394	91	303	394	0	0	$16.50	$11.87	$0.00	$0.00	$0.45	$11.73	$9.51	-$0.84	$49.22
Small	636	146	490	400	236	0	$16.50	$12.07	$10.19	$0.00	$0.73	$18.96	$15.37	-$1.36	$72.46
Medium	1633	376	1,257	400	1,233	0	$16.50	$12.07	$53.24	$0.00	$1.86	$48.68	$39.46	-$3.49	$168.32
Large	2,328	535	1,793	400	1,928	0	$16.50	$12.07	$83.24	$0.00	$2.65	$69.40	$56.26	-$4.98	$235.14
XLg	3,091	711	2,380	400	2,691	0	$16.50	$12.07	$116.19	$0.00	$3.52	$92.14	$74.70	-$6.61	$308.51
WinAvg	1,551	357	1,194	400	1,151	0	$16.50	$12.07	$49.70	$0.00	$1.77	$46.24	$37.48	-$3.32	$160.44

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+							
	Winter	0.23					$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.108800	$0.040036	-11.144%			
	Summer	0.18										$0.109800	$0.045800				
Xsm	394	91	303	394	0	0	$30.00	$12.75	$0.00	$0.00	$0.00	$9.85	$12.13	($2.45)	$62.28	$13.06	26.54%
Small	636	146	490	400	236	0	$30.00	$12.96	$10.01	$0.00	$0.00	$15.92	$19.61	($3.96)	$84.54	$12.08	16.67%
Medium	1,633	376	1,257	400	1,233	0	$30.00	$12.96	$52.28	$0.00	$0.00	$40.86	$50.34	($10.16)	$176.28	$7.96	4.73%
Large	2,328	535	1,793	400	1,928	0	$30.00	$12.96	$81.75	$0.00	$0.00	$58.26	$71.77	($14.49)	$240.25	$5.11	2.17%
XLg	3,091	711	2,380	400	2,691	0	$30.00	$12.96	$114.10	$0.00	$0.00	$77.35	$95.29	($19.24)	$310.46	$1.95	0.63%
WinAvg	1,551	357	1,194	400	1,151	0	$30.00	$12.96	$48.81	$0.00	$0.00	$38.81	$47.82	($9.65)	$168.75	$8.31	5.18%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE RATE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23													
	Summer	0.18										$0.129605	$0.031385		
							$16.50	$0.030176	$0.043176	$0.076042	$0.001140	$0.129605	$0.039605	-$0.002139	
Xsm	781	141	640	400	381	0	$16.50	$12.07	$16.45	$0.00	$0.89	$18.22	$25.36	-$1.67	$87.82
Small	1220	220	1,000	400	820	0	$16.50	$12.07	$35.40	$0.00	$1.39	$28.46	$39.62	-$2.61	$130.83
Medium	2350	423	1,927	400	1,950	0	$16.50	$12.07	$84.17	$0.00	$2.68	$54.81	$76.30	-$5.03	$241.50
Large	3,078	554	2,524	400	2,678	0	$16.50	$12.07	$115.63	$0.00	$3.51	$71.81	$99.96	-$6.58	$312.90
XLg	3,640	655	2,985	400	3,240	0	$16.50	$12.07	$139.89	$0.00	$4.15	$84.92	$118.21	-$7.79	$367.95
SumAvg	2,256	406	1,850	400	1,856	0	$16.50	$12.07	$80.15	$0.00	$2.57	$52.64	$73.28	-$4.83	$232.38

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+							
	Winter	0.23					$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.108800	$0.040036				
	Summer	0.18										$0.109800	$0.045800	-11.144%		$ Change	% Change
Xsm	781	141	640	400	381	0	$30.00	$12.96	$16.15	$0.00	$0.00	$15.44	$29.33	($4.99)	$98.89	$11.07	12.61%
Small	1,220	220	1,000	400	820	0	$30.00	$12.96	$34.77	$0.00	$0.00	$24.11	$45.82	($7.79)	$139.87	$9.04	6.91%
Medium	2,350	423	1,927	400	1,950	0	$30.00	$12.96	$82.66	$0.00	$0.00	$46.44	$88.24	($15.01)	$245.29	$3.79	1.57%
Large	3,078	554	2,524	400	2,678	0	$30.00	$12.96	$113.55	$0.00	$0.00	$60.83	$115.60	($19.66)	$313.28	$0.38	0.12%
XLg	3,640	655	2,985	400	3,240	0	$30.00	$12.96	$137.38	$0.00	$0.00	$71.94	$136.70	($23.25)	$365.73	($2.22)	-0.60%
SumAvg	2,256	406	1,850	400	1,856	0	$30.00	$12.96	$78.71	$0.00	$0.00	$44.59	$84.74	($14.41)	$236.59	$4.21	1.81%

	Net Bill	$ Change	% Change
Current Annual	$2,356.95		
Proposed Annual	$2,432.04	$75.09	3.19%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE RATE TIME OF USE DEMAND

WINTER

BILL IMPACTS PROPOSED SGS-TOU RATES

	Energy (kWh)	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23					$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.108800	$0.040036	0.000%	
	Summer	0.18										$0.109800	$0.045800		
Xsm	394	91	303	394	0	0	$30.00	$12.75	$0.00	$0.00	$0.00	$9.85	$12.13	$0.00	$64.73
Small	636	146	490	400	236	0	$30.00	$12.96	$10.01	$0.00	$0.00	$15.92	$19.61	$0.00	$88.50
Medium	1633	376	1,257	400	1,233	0	$30.00	$12.96	$52.28	$0.00	$0.00	$40.86	$50.34	$0.00	$186.44
Large	2,328	535	1,793	400	1,928	0	$30.00	$12.96	$81.75	$0.00	$0.00	$58.26	$71.77	$0.00	$254.74
XLg	3,091	711	2,380	400	2,691	0	$30.00	$12.96	$114.10	$0.00	$0.00	$77.35	$95.29	$0.00	$329.70
WinAvg	1,551	357	1,194	400	1,151	0	$30.00	$12.96	$48.81	$0.00	$0.00	$38.81	$47.82	$0.00	$178.40

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)	Basic Service Charge	Delivery		TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak			30.00	All kW	All kWh		On-Peak	Off-Peak				
							5.49	$0.016680	$0.000000						
	Winter	0.23								$0.083570	$0.040036	-11.144%			
	Summer	0.18								$0.084570	$0.045800				
Xsm	394	91	303	32%	1.7	$30.00	$9.33	$6.56	$0.00	$7.56	$12.13	($2.19)	$63.39	-$1.34	-2.07%
Small	636	146	490	35%	2.5	$30.00	$13.73	$10.61	$0.00	$12.22	$19.61	($3.55)	$82.62	-$5.88	-6.64%
Medium	1633	376	1,257	42%	5.4	$30.00	$29.65	$27.24	$0.00	$31.39	$50.34	($9.11)	$159.51	-$26.93	-14.44%
Large	2,328	535	1,793	44%	7.2	$30.00	$39.53	$38.83	$0.00	$44.75	$71.77	($12.98)	$211.90	-$42.84	-16.82%
XLg	3,091	711	2,380	47%	9.0	$30.00	$49.41	$51.56	$0.00	$59.41	$95.29	($17.24)	$268.43	-$61.27	-18.58%
WinAvg	1,551	357	1,194	41%	5.2	$30.00	$28.55	$25.87	$0.00	$29.81	$47.82	($8.65)	$153.40	-$25.00	-14.01%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

SMALL GENERAL SERVICE RATE TIME OF USE DEMAND

SUMMER

BILL IMPACTS PROPOSED SGS-TOU RATES

	Energy (kWh)	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23					$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.108800	$0.040036		
	Summer	0.18										$0.109800	$0.045800	0.000%	
Xsm	781	141	640	400	381	0	$30.00	$12.96	$16.15	$0.00	$0.00	$15.44	$29.33	$0.00	$103.88
Small	1220	220	1,000	400	820	0	$30.00	$12.96	$34.77	$0.00	$0.00	$24.11	$45.82	$0.00	$147.66
Medium	2350	423	1,927	400	1,950	0	$30.00	$12.96	$82.66	$0.00	$0.00	$46.44	$88.24	$0.00	$260.30
Large	3,078	554	2,524	400	2,678	0	$30.00	$12.96	$113.55	$0.00	$0.00	$60.83	$115.60	$0.00	$332.94
XLg	3,640	655	2,985	400	3,240	0	$30.00	$12.96	$137.38	$0.00	$0.00	$71.94	$136.70	$0.00	$388.98
SumAvg	2,256	406	1,850	400	1,856	0	$30.00	$12.96	$78.71	$0.00	$0.00	$44.59	$84.74	$0.00	$251.00

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)			Basic Service Charge	Delivery		TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak						All kW	All kWh		On-Peak	Off-Peak				
	Winter	0.23						30.00	5.49	$0.016680	$0.000000	$0.083570	$0.040036				
	Summer	0.18										$0.084570	$0.045800	-11.144%			
Xsm	781	141	640	36%	3.0			$30.00	$16.47	$13.03	$0.00	$11.89	$29.33	($4.59)	$96.13	-$7.75	-7.46%
Small	1,220	220	1,000	39%	4.3			$30.00	$23.61	$20.35	$0.00	$18.57	$45.82	($7.18)	$131.17	-$16.49	-11.17%
Medium	2,350	423	1,927	45%	7.2			$30.00	$39.53	$39.19	$0.00	$35.77	$88.24	($13.82)	$218.91	-$41.39	-15.90%
Large	3,078	554	2,524	47%	9.0			$30.00	$49.41	$51.34	$0.00	$46.86	$115.60	($18.10)	$275.11	-$57.83	-17.37%
XLg	3,640	655	2,985	48%	10.3			$30.00	$56.55	$60.72	$0.00	$55.41	$136.70	($21.41)	$317.97	-$71.01	-18.26%
SumAvg	2,256	406	1,850	44%	7.0			$30.00	$38.43	$37.64	$0.00	$34.35	$84.74	($13.27)	$211.89	-$39.11	-15.58%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

	Net Bill	$ Change	% Change
Current Annual	$2,576.40		
Proposed Annual	$2,191.74	($384.66)	-14.93%

INTERRUPTIBLE POWER SERVICE

BILL IMPACTS CURRENT RATES

	Load Factor	Total kWh	Demand (kW)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$18.00	$5.00	$0.019408	$0.432900	0.043760	-$0.002139	
Xsm	40.3%	1,116	66	$18.00	$331.53	$21.65	$28.70	$48.82	-$2.39	$446.32
Small	27.4%	14,651	108	$18.00	$541.23	$284.34	$46.86	$641.11	-$31.34	$1,500.20
Medium	30.7%	29,389	154	$18.00	$768.97	$570.39	$66.58	$1,286.08	-$62.87	$2,647.15
Large	44.3%	71,334	237	$18.00	$1,183.91	$1,384.44	$102.50	$3,121.55	-$152.61	$5,657.79
XLg	58.4%	384,599	887	$18.00	$4,432.94	$7,464.30	$383.80	$16,830.06	-$822.79	$28,306.31
AnnAvg	56.0%	97,708	239	$18.00	$1,195.06	$1,896.33	$103.47	$4,275.72	-$209.03	$7,279.55
AvgWin	52.0%	83,072	219	$18.00	$1,094.21	$1,612.26	$94.74	$3,635.24	-$177.72	$6,276.73
AvgSum	62.0%	112,958	250	$18.00	$1,247.88	$2,192.29	$108.04	$4,943.03	-$241.65	$8,267.58
Annual										$87,265.86

BILL IMPACTS PROPOSED RATES

	Load Factor	Total kWh	Demand (kW)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$75.00	$5.50	$0.019800	$0.000000	$0.053090	-11.144%			
Xsm	40.3%	1,116	66	$75.00	$364.69	$22.09	$0.00	$59.23	($6.60)	$514.41	$68.09	15.26%
Small	27.4%	14,651	108	$75.00	$595.36	$290.08	$0.00	$777.80	($86.68)	$1,651.56	$151.36	10.09%
Medium	30.7%	29,389	154	$75.00	$845.87	$581.91	$0.00	$1,560.28	($173.87)	$2,889.19	$242.04	9.14%
Large	44.3%	71,334	237	$75.00	$1,302.30	$1,412.40	$0.00	$3,787.10	($422.02)	$6,154.78	$496.99	8.78%
XLg	58.4%	384,599	887	$75.00	$4,876.23	$7,615.06	$0.00	$20,418.37	($2,275.35)	$30,709.31	$2,403.00	8.49%
AnnAvg	56.0%	97,708	239	$75.00	$1,314.57	$1,934.63	$0.00	$5,187.34	($578.06)	$7,933.48	$653.93	8.98%
AvgWin	52.0%	83,072	219	$75.00	$1,203.63	$1,644.83	$0.00	$4,410.30	($491.47)	$6,842.29	$565.56	9.01%
AvgSum	62.0%	112,958	250	$75.00	$1,372.66	$2,236.57	$0.00	$5,996.93	($668.28)	$9,012.88	$745.31	9.01%
Annual										$95,131.03	$7,865.17	9.01%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

MEDIUM GENERAL SERVICE

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$50.00	$12.81	$0.005470	$0.432900	$0.056603	-$0.002139	
Xsm	0.46	20	4,040	$50.00	$256.20	$22.10	$8.66	$228.68	-$8.64	$557.00
Small	0.46	20	6,400	$50.00	$256.20	$35.01	$8.66	$362.26	-$13.69	$698.44
Medium	0.46	36	12,160	$50.00	$463.88	$66.52	$15.68	$688.29	-$26.01	$1,258.36
Large	0.46	80	26,880	$50.00	$1,025.41	$147.03	$34.65	$1,521.49	-$57.51	$2,721.07
Xlarge	0.46	294	98,640	$50.00	$3,762.89	$539.56	$127.16	$5,583.32	-$211.02	$9,851.91
AnnAvg	0.46	80	26,796	$50.00	$1,022.22	$146.58	$34.54	$1,516.76	-$57.33	$2,712.77
sum	0.46	90	30,153	$50.00	$1,150.28	$164.94	$38.87	$1,706.76	-$64.51	$3,046.34
win	0.46	70	23,520	$50.00	$897.22	$128.65	$30.32	$1,331.28	-$50.32	$2,387.15
Annual										$32,600.94

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$100.00	$13.95	$0.005500	$0.000000	$0.053290	-11.144%			
Xsm	0.46	20	4,040	$100.00	$279.00	$22.22	$0.00	$215.29	($23.99)	$592.52	$35.52	6.4%
Small	0.46	20	6,400	$100.00	$279.00	$35.20	$0.00	$341.06	($38.01)	$717.25	$18.81	2.7%
Medium	0.46	36	12,160	$100.00	$505.16	$66.88	$0.00	$648.01	($72.21)	$1,247.84	-$10.52	-0.8%
Large	0.46	80	26,880	$100.00	$1,116.66	$147.84	$0.00	$1,432.44	($159.63)	$2,637.31	-$83.76	-3.1%
Xlarge	0.46	294	98,640	$100.00	$4,097.76	$542.52	$0.00	$5,256.53	($585.77)	$9,411.04	-$440.87	-4.5%
AnnAvg	0.46	80	26,796	$100.00	$1,113.19	$147.38	$0.00	$1,427.98	($159.13)	$2,629.42	-$83.35	-3.1%
sum	0.46	90	30,153	$100.00	$1,252.64	$165.84	$0.00	$1,606.87	($179.06)	$2,946.29	-$100.05	-3.3%
win	0.46	70	23,520	$100.00	$977.06	$129.36	$0.00	$1,253.36	($139.67)	$2,320.11	-$67.04	-2.8%
Annual										$31,598.40	-$1,002.54	-3.1%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

MEDIUM GENERAL SERVICE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
		Winter		0.29		$52.00	$12.81	$0.005470	$0.43290	0.114886	0.026168	-$0.002139	
		Summer		0.20						0.114886	0.039886		
Xsm	0.46	27,974	83	8,112	19,862	$52.00	$1,067.14	$153.02	$36.06	$932.01	$519.74	-$59.85	$2,700.12
Small	0.46	28,067	84	8,139	19,928	$52.00	$1,070.69	$153.53	$36.18	$935.11	$521.46	-$60.04	$2,708.93
Medium	0.46	48,453	144	14,051	34,402	$52.00	$1,848.37	$265.04	$62.46	$1,614.31	$900.22	-$103.66	$4,638.74
Large	0.56	62,572	186	18,146	44,426	$52.00	$2,386.98	$342.27	$80.67	$2,084.71	$1,162.54	-$133.86	$5,975.31
XLg	0.66	193,470	576	56,106	137,364	$52.00	$7,380.44	$1,058.28	$249.41	$6,445.83	$3,594.53	-$413.90	$18,366.59
AnnAvg	0.58	69,713	208	20,217	49,496	$52.00	$2,659.39	$381.33	$89.87	$2,322.62	$1,295.22	-$149.14	$6,651.29
AvgWin	0.56	65,673	196	19,045	46,628	$52.00	$2,505.28	$359.23	$84.66	$2,188.02	$1,220.16	-$140.50	$6,268.85

BILL IMPACTS PROPOSED RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
		Winter				$100.00	$13.95	$0.005500	$0.00000	0.101047	0.031690	-11.144%			
		Summer								0.114886	0.033500				
Xsm	0.46	27,974	83	8,112	19,862	$100.00	$1,162.11	$153.86	$0.00	$819.74	$629.41	($161.49)	$2,703.63	$3.51	0.1%
Small	0.46	28,067	84	8,139	19,928	$100.00	$1,165.98	$154.37	$0.00	$822.46	$631.50	($162.02)	$2,712.29	$3.36	0.1%
Medium	0.46	48,453	144	14,051	34,402	$100.00	$2,012.86	$266.49	$0.00	$1,419.85	$1,090.19	($279.71)	$4,609.68	-$29.06	-0.6%
Large	0.56	62,572	186	18,146	44,426	$100.00	$2,599.40	$344.15	$0.00	$1,833.59	$1,407.86	($361.22)	$5,923.78	-$51.53	-0.9%
XLg	0.66	193,470	576	56,106	137,364	$100.00	$8,037.24	$1,064.09	$0.00	$5,669.37	$4,353.06	($1,116.87)	$18,106.89	-$259.70	-1.4%
AnnAvg	0.58	69,713	208	20,217	49,496	$100.00	$2,896.06	$383.42	$0.00	$2,042.84	$1,568.53	($402.44)	$6,588.41	-$62.88	-0.9%
AvgWin	0.56	65,673	196	19,045	46,628	$100.00	$2,728.23	$361.20	$0.00	$1,924.46	$1,477.64	($379.12)	$6,212.41	-$56.44	-0.9%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

MEDIUM GENERAL SERVICE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
		Winter		0.29		$52.00	$12.81	$0.005470	$0.43290	0.114886	0.026168		
		Summer		0.20						0.114886	0.039886	-$0.002139	
Xsm	0.46	27,974	83	5,595	22,379	$52.00	$1,067.14	$153.02	$36.06	$642.76	$892.62	-$59.85	$2,783.75
Small	0.46	28,067	84	5,613	22,454	$52.00	$1,070.69	$153.53	$36.18	$644.90	$895.58	-$60.04	$2,792.84
Medium	0.46	48,453	144	9,691	38,762	$52.00	$1,848.37	$265.04	$62.46	$1,113.31	$1,546.08	-$103.66	$4,783.60
Large	0.56	62,572	186	12,514	50,058	$52.00	$2,386.98	$342.27	$80.67	$1,437.73	$1,996.60	-$133.86	$6,162.39
XLg	0.66	193,470	576	38,694	154,776	$52.00	$7,380.44	$1,058.28	$249.41	$4,445.40	$6,173.40	-$413.90	$18,945.03
AnnAvg	0.58	69,713	208	13,943	55,770	$52.00	$2,659.39	$381.33	$89.87	$1,601.81	$2,224.46	-$149.14	$6,859.72
AvgSum	0.56	73,609	219	14,722	58,887	$52.00	$2,808.00	$402.64	$94.89	$1,691.32	$2,348.76	-$157.47	$7,240.14

BILL IMPACTS PROPOSED RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
		Winter				$100.00	$13.95	$0.005500	$0.00000	0.101047	0.031690				
		Summer								0.114886	0.033500	-11.144%			
Xsm	0.46	27,974	83	5,595	22,379	$100.00	$1,162.11	$153.86	$0.00	$642.76	$749.70	($155.17)	$2,653.26	-$130.49	-4.7%
Small	0.46	28,067	84	5,613	22,454	$100.00	$1,165.98	$154.37	$0.00	$644.90	$752.20	($155.69)	$2,661.76	-$131.08	-4.7%
Medium	0.46	48,453	144	9,691	38,762	$100.00	$2,012.86	$266.49	$0.00	$1,113.31	$1,298.54	($268.77)	$4,522.43	-$261.17	-5.5%
Large	0.56	62,572	186	12,514	50,058	$100.00	$2,599.40	$344.15	$0.00	$1,437.73	$1,676.93	($347.09)	$5,811.12	-$351.27	-5.7%
XLg	0.66	193,470	576	38,694	154,776	$100.00	$8,037.24	$1,064.09	$0.00	$4,445.40	$5,185.00	($1,073.18)	$17,758.55	-$1,186.48	-6.3%
AnnAvg	0.58	69,713	208	13,943	55,770	$100.00	$2,896.06	$383.42	$0.00	$1,601.81	$1,868.31	($386.70)	$6,462.90	-$396.82	-5.8%
AvgSum	0.56	73,609	219	14,722	58,887	$100.00	$3,057.89	$404.85	$0.00	$1,691.32	$1,972.71	($408.31)	$6,818.46	-$421.68	-5.8%

	$ Change	% Change	
Current Annual	$81,053.94		
Proposed Annual	$78,185.22	-$2,868.72	-3.5%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE GENERAL SERVICE TO NEW LARGE GENERAL SERVICE

BILL IMPACTS CURRENT RATES - LGS

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$50.00	$12.81	$0.005470	$0.43290	0.056603	-$0.002139	
Xsm	30%	205	45,000	$50.00	$2,632.19	$246.15	$88.95	$2,547.14	-$96.27	$5,468.16
Small	46%	194	65,000	$50.00	$2,479.60	$355.55	$83.80	$3,679.20	-$139.06	$6,509.09
Medium	66%	844	406,600	$50.00	$10,810.60	$2,224.10	$365.33	$23,014.78	-$869.85	$35,594.96
Large	75%	174	95,000	$50.00	$2,222.74	$519.65	$75.12	$5,377.29	-$203.24	$8,041.56
XLg	95%	1,875	1,300,500	$50.00	$24,022.21	$7,113.74	$811.80	$73,612.20	-$2,782.20	$102,827.75
AnnAvg	65%	992	470,630	$50.00	$12,705.52	$2,574.35	$429.37	$26,639.07	-$1,006.83	$41,391.47

BILL IMPACTS PROPOSED RATES - LGS

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$300.00	$13.35	$0.005470	$0.00000	$0.053290	-11.144%			
Xsm	30%	450	45,000	$300.00	$6,007.50	$246.15	$0.00	$2,398.05	($267.23)	$8,684.47	$3,216.31	58.8%
Small	46%	450	65,000	$300.00	$6,007.50	$355.55	$0.00	$3,463.85	($386.00)	$9,740.90	$3,231.81	49.7%
Medium	66%	844	406,600	$300.00	$11,266.31	$2,224.10	$0.00	$21,667.71	($2,414.58)	$33,043.55	-$2,551.41	-7.2%
Large	75%	450	95,000	$300.00	$6,007.50	$519.65	$0.00	$5,062.55	($564.15)	$11,325.55	$3,283.99	40.8%
XLg	95%	1,875	1,300,500	$300.00	$25,034.86	$7,113.74	$0.00	$69,303.65	($7,722.96)	$94,029.28	-$8,798.46	-8.6%
AnnAvg	65%	992	470,630	$300.00	$13,241.12	$2,574.35	$0.00	$25,079.87	($2,794.82)	$38,400.51	-$2,990.96	-7.2%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE <69kV TO NEW LARGE GENERAL SERVICE

BILL IMPACTS CURRENT RATES - LPS <69kV

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$1,200.00	$22.00	$0.000462	$0.43290	$0.04188	-$0.002139	
Xsm	44%	747	240,000	$1,200.00	$16,438.36	$110.88	$323.46	$10,051.20	-$513.44	$27,610.46
Small	46%	893	300,000	$1,200.00	$19,654.56	$138.60	$386.75	$12,564.00	-$641.80	$33,302.11
Medium	66%	844	406,600	$1,200.00	$18,566.21	$187.85	$365.33	$17,028.41	-$869.85	$36,477.95
Large	75%	1,553	850,000	$1,200.00	$34,155.25	$392.70	$672.08	$35,598.00	-$1,818.43	$70,199.60
XLg	75%	2,192	1,200,000	$1,200.00	$48,219.18	$554.40	$948.82	$50,256.00	-$2,567.20	$98,611.20
AnnAvg	65%	992	470,630	$1,200.00	$21,820.57	$217.43	$429.37	$19,709.98	-$1,006.83	$42,370.52

BILL IMPACTS PROPOSED RATES - LPS <69 kV

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$300.00	$13.35	$0.005470	$0.00000	$0.053290	-11.144%			
Xsm	44%	747	240,000	$300.00	$9,975.09	$1,312.80	$0.00	$12,789.60	($1,425.23)	$22,952.26	-$4,658.19	-16.9%
Small	46%	893	300,000	$300.00	$11,926.74	$1,641.00	$0.00	$15,987.00	($1,781.54)	$28,073.20	-$5,228.90	-15.7%
Medium	66%	844	406,600	$300.00	$11,266.31	$2,224.10	$0.00	$21,667.71	($2,414.58)	$33,043.55	-$3,434.40	-9.4%
Large	75%	1,553	850,000	$300.00	$20,726.03	$4,649.50	$0.00	$45,296.50	($5,047.69)	$65,924.34	-$4,275.26	-6.1%
XLg	75%	2,192	1,200,000	$300.00	$29,260.27	$6,564.00	$0.00	$63,948.00	($7,126.15)	$92,946.12	-$5,665.07	-5.7%
AnnAvg	65%	992	470,630	$300.00	$13,241.12	$2,574.35	$0.00	$25,079.87	($2,794.82)	$38,400.51	-$3,970.00	-9.4%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE TIME OF USE <69kV TO NEW LARGE GENERAL SERVICE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
	Winter		0.16		$1,200.00	$22.00	$0.000462	$0.43290	$0.093880	$0.022105	-$0.002139	
	Summer		0.16						$0.123580	$0.024716		
Small	433,335	1,281	69,334	364,001	$1,200.00	$28,182.00	$200.20	$554.54	$6,509.04	$8,046.25	-$927.05	$43,764.98
Medium	517,000	1,380	82,720	434,280	$1,200.00	$30,360.00	$238.85	$597.40	$7,765.75	$9,599.76	-$1,106.04	$48,655.72
Large	600,000	1,400	96,000	504,000	$1,200.00	$30,800.00	$277.20	$606.06	$9,012.48	$11,140.92	-$1,283.60	$51,753.06
XLg	775,000	1,570	124,000	651,000	$1,200.00	$34,540.00	$358.05	$679.65	$11,641.12	$14,390.36	-$1,657.98	$61,151.20
Mean	642,400	1,430	102,784	539,616	$1,200.00	$31,460.00	$296.79	$619.05	$9,649.36	$11,928.21	-$1,374.31	$53,779.10
AvgWin	627,900	1,416	100,464	527,436	$1,200.00	$31,152.00	$290.09	$612.99	$9,431.56	$11,658.97	-$1,343.29	$53,002.32

BILL IMPACTS PROPOSED RATES

	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
	Winter				$300.00	$13.35	$0.005470	$0.00000	$0.139880	$0.034927	-11.144%			
	Summer								$0.143771	$0.038600				
Small	433,335	1,281	69,334	364,001	$300.00	$17,101.35	$2,370.34	$0.00	$9,698.38	$12,713.48	($2,497.50)	$39,686.05	-$4,078.93	-9.3%
Medium	517,000	1,380	82,720	434,280	$300.00	$18,423.00	$2,827.99	$0.00	$11,570.87	$15,168.10	($2,979.70)	$45,310.26	-$3,345.46	-6.9%
Large	600,000	1,400	96,000	504,000	$300.00	$18,690.00	$3,282.00	$0.00	$13,428.48	$17,603.21	($3,458.07)	$49,845.62	-$1,907.44	-3.7%
XLg	775,000	1,570	124,000	651,000	$300.00	$20,959.50	$4,239.25	$0.00	$17,345.12	$22,737.48	($4,466.67)	$61,114.68	-$36.52	-0.1%
Mean	642,400	1,430	102,784	539,616	$300.00	$19,090.50	$3,513.93	$0.00	$14,377.43	$18,847.17	($3,702.44)	$52,426.59	-$1,352.51	-2.5%
AvgWin	627,900	1,416	100,464	527,436	$300.00	$18,903.60	$3,434.61	$0.00	$14,052.90	$18,421.76	($3,618.87)	$51,494.00	-$1,508.32	-2.8%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE TIME OF USE <69kV TO NEW LARGE GENERAL SERVICE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
	Winter		0.16		$1,200.00	$22.00	$0.000462	$0.43290	$0.093880	$0.022105		
	Summer		0.16						$0.123580	$0.024716	-$0.002139	
Small	433,335	1,281	69,334	364,001	$1,200	$28,182.00	$200.20	$554.54	$8,568.25	$8,996.66	-$927.05	$46,774.60
Medium	517,000	1,380	82,720	434,280	$1,200	$30,360.00	$238.85	$597.40	$10,222.54	$10,733.66	-$1,106.04	$52,246.41
Large	600,000	1,400	96,000	504,000	$1,200	$30,800.00	$277.20	$606.06	$11,863.68	$12,456.86	-$1,283.60	$55,920.20
XLg	775,000	1,570	124,000	651,000	$1,200	$34,540.00	$358.05	$679.65	$15,323.92	$16,090.12	-$1,657.98	$66,533.76
Mean	642,400	1,430	102,784	539,616	$1,200	$31,460.00	$296.79	$619.05	$12,702.05	$13,337.15	-$1,374.31	$58,240.73
AvgSum	656,700	1,444	105,072	551,628	$1,200	$31,768.00	$303.40	$625.11	$12,984.80	$13,634.04	-$1,404.90	$59,110.45

BILL IMPACTS PROPOSED RATES

	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
	Winter				$300.00	$13.35	$0.005470	$0.00000	$0.139880	$0.034927				
	Summer								$0.143771	$0.038600	-11.144%			
Small	433,335	1,281	69,334	364,001	$300.00	$17,101.35	$2,370.34	$0.00	$9,968.16	$14,050.45	($2,676.55)	$41,113.75	-$5,660.85	-12.1%
Medium	517,000	1,380	82,720	434,280	$300.00	$18,423.00	$2,827.99	$0.00	$11,892.74	$16,763.21	($3,193.32)	$47,013.62	-$5,232.79	-10.0%
Large	600,000	1,400	96,000	504,000	$300.00	$18,690.00	$3,282.00	$0.00	$13,802.02	$19,454.40	($3,705.98)	$51,822.44	-$4,097.76	-7.3%
XLg	775,000	1,570	124,000	651,000	$300.00	$20,959.50	$4,239.25	$0.00	$17,827.60	$25,128.60	($4,786.89)	$63,668.06	-$2,865.70	-4.3%
Mean	642,400	1,430	102,784	539,616	$300.00	$19,090.50	$3,513.93	$0.00	$14,777.36	$20,829.18	($3,967.87)	$54,543.10	-$3,697.63	-6.3%
AvgSum	656,700	1,444	105,072	551,628	$300.00	$19,277.40	$3,592.15	$0.00	$15,106.31	$21,292.84	($4,056.20)	$55,512.50	-$3,597.95	-6.1%

		$ Change	% Change
Current Annual	$672,676.62		
Proposed Annual	$642,039.00	-$30,637.62	-4.55%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE - TRANSMISSION VOLTAGE

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$1,200.00	$17.00	$0.000462	$0.43290	$0.041880	-$0.002139	
Xsm	0.42	506	155,000	$1,200.00	$8,594.26	$71.61	$218.85	$6,491.40	-$331.60	$16,244.52
Small	0.42	1,267	388,500	$1,200.00	$21,541.10	$179.49	$548.54	$16,270.38	-$831.13	$38,908.37
Small	0.46	1,336	448,600	$1,200.00	$22,710.54	$207.25	$578.32	$18,787.37	-$959.70	$42,523.79
Medium	0.75	2,416	1,322,700	$1,200.00	$41,070.14	$611.09	$1,045.84	$55,394.68	-$2,829.70	$96,492.04
Medium	0.75	2,817	1,542,200	$1,200.00	$47,885.66	$712.50	$1,219.39	$64,587.34	-$3,299.28	$112,305.61
Large	0.89	4,775	3,102,500	$1,200.00	$81,179.78	$1,433.36	$2,067.22	$129,932.70	-$6,637.28	$209,175.77
Large	0.89	5,379	3,494,900	$1,200.00	$91,447.28	$1,614.64	$2,328.68	$146,366.41	-$7,476.76	$235,480.26

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$1,500.00	$13.00	$0.000500	$0.00000	$0.049332	-11.144%			
Xsm	0.42	506	155,000	$1,500.00	$6,572.08	$77.50	$0.00	$7,646.43	($852.09)	$14,943.92	-$1,300.60	-8.0%
Small	0.42	1,267	388,500	$1,500.00	$16,472.60	$194.25	$0.00	$19,165.41	($2,135.73)	$35,196.53	-$3,711.84	-9.5%
Small	0.46	1,336	448,600	$1,500.00	$17,366.89	$224.30	$0.00	$22,130.26	($2,466.12)	$38,755.33	-$3,768.46	-8.9%
Medium	0.75	2,416	1,322,700	$1,500.00	$31,406.58	$661.35	$0.00	$65,251.21	($7,271.37)	$91,547.77	-$4,944.28	-5.1%
Medium	0.75	2,817	1,542,200	$1,500.00	$36,618.45	$771.10	$0.00	$76,079.54	($8,478.05)	$106,491.04	-$5,814.57	-5.2%
Large	0.89	4,775	3,102,500	$1,500.00	$62,078.65	$1,551.25	$0.00	$153,051.99	($17,055.59)	$201,126.30	-$8,049.47	-3.8%
Large	0.89	5,379	3,494,900	$1,500.00	$69,930.28	$1,747.45	$0.00	$172,409.80	($19,212.76)	$226,374.77	-$9,105.49	-3.9%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE TIME OF USE >69kV

WINTER

BILL IMPACTS CURRENT RATES

	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill
	Winter				$1,200.00	$17.00	$0.000462	$0.43290	$0.093880	$0.022105	-$0.002139	
	Summer		0.11	0.89					$0.123580	$0.024716		
Small	2,790,000	5,083	306,900	2,483,100	$1,200.00	$86,411.00	$1,288.98	$2,200.43	$28,811.77	$54,888.93	-$5,967.81	$168,833.30
Medium	3,150,000	5,083	346,500	2,803,500	$1,200.00	$86,411.00	$1,455.30	$2,200.43	$32,529.42	$61,971.37	-$6,737.85	$179,029.67
Large	2,115,000	5,083	232,650	1,882,350	$1,200.00	$86,411.00	$977.13	$2,200.43	$21,841.18	$41,609.35	-$4,523.99	$149,715.10
Mean	2,717,000	5,083	298,870	2,418,130	$1,200.00	$86,411.00	$1,255.25	$2,200.43	$28,057.92	$53,452.76	-$5,811.66	$166,765.70
AvgWin	2,726,000	5,083	299,860	2,426,140	$1,200.00	$86,411.00	$1,259.41	$2,200.43	$28,150.86	$53,629.82	-$5,830.91	$167,020.61

BILL IMPACTS PROPOSED RATES

	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill	$ Change	% Change
	Winter				$1,500.00	$13.00	$0.000500	$0.00000	$0.092110	$0.030410	-11.144%			
	Summer								$0.125155	$0.033410				
Small	2,790,000	5,083	306,900	2,483,100	$1,500.00	$66,079.00	$1,395.00	$0.00	$28,268.56	$75,511.07	($11,564.85)	$161,188.78	-$7,644.52	-4.53%
Medium	3,150,000	5,083	346,500	2,803,500	$1,500.00	$66,079.00	$1,575.00	$0.00	$31,916.12	$85,254.44	($13,057.09)	$173,267.47	-$5,762.20	-3.22%
Large	2,115,000	5,083	232,650	1,882,350	$1,500.00	$66,079.00	$1,057.50	$0.00	$21,429.39	$57,242.26	($8,766.90)	$138,541.25	-$11,173.85	-7.46%
Mean	2,717,000	5,083	298,870	2,418,130	$1,500.00	$66,079.00	$1,358.50	$0.00	$27,528.92	$73,535.33	($11,262.26)	$158,739.49	-$8,026.21	-4.81%
AvgWin	2,726,000	5,083	299,860	2,426,140	$1,500.00	$66,079.00	$1,363.00	$0.00	$27,620.10	$73,778.92	($11,299.56)	$159,041.46	-$7,979.15	-4.78%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE TIME OF USE >69kV

SUMMER

BILL IMPACTS CURRENT RATES

	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill
	Winter								$0.093880	$0.022105		
	Summer		0.11	0.89	$1,200.00	$17.00	$0.000462	$0.43290	$0.123580	$0.024716	-$0.002139	
Small	2,790,000	5,083	306,900	2,483,100	$1,200.00	$86,411.00	$1,288.98	$2,200.43	$37,926.70	$61,372.30	-$5,967.81	$184,431.60
Medium	3,150,000	5,083	346,500	2,803,500	$1,200.00	$86,411.00	$1,455.30	$2,200.43	$42,820.47	$69,291.31	-$6,737.85	$196,640.66
Large	2,115,000	5,083	232,650	1,882,350	$1,200.00	$86,411.00	$977.13	$2,200.43	$28,750.89	$46,524.16	-$4,523.99	$161,539.62
Mean	2,717,000	5,083	298,870	2,418,130	$1,200.00	$86,411.00	$1,255.25	$2,200.43	$36,934.35	$59,766.50	-$5,811.66	$181,955.87
AvgSum	2,790,000	5,083	311,600	2,478,400	$1,200.00	$86,411.00	$1,288.98	$2,200.43	$38,507.53	$61,256.13	-$5,967.81	$184,896.26

BILL IMPACTS PROPOSED RATES

	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill	$ Change	% Change
	Winter								$0.092110	$0.030410				
	Summer				$1,500.00	$13.00	$0.000500	$0.00000	$0.125155	$0.033410	-11.144%			
Small	2,790,000	5,083	306,900	2,483,100	$1,500	$66,079	$1,395	$0.00	$38,410.07	$82,960.37	($13,525.11)	$176,819	-$7,612.27	-4.13%
Medium	3,150,000	5,083	346,500	2,803,500	$1,500	$66,079	$1,575	$0.00	$43,366.21	$93,664.94	($15,270.29)	$190,915	-$5,725.80	-2.91%
Large	2,115,000	5,083	232,650	1,882,350	$1,500	$66,079	$1,058	$0.00	$29,117.31	$62,889.31	($10,252.90)	$150,390	-$11,149.40	-6.90%
Mean	2,717,000	5,083	298,870	2,418,130	$1,500	$66,079	$1,359	$0.00	$37,405.07	$80,789.72	($13,171.23)	$173,961	-$7,994.81	-4.39%
AvgSum	2,790,000	5,083	311,600	2,478,400	$1,500	$66,079	$1,395	$0.00	$38,998.30	$82,803.34	($13,573.16)	$177,202	-$7,693.78	-4.16%

	Total	$ Change	% Change
Current Annual	$2,111,501		
Proposed Annual	$2,017,464	($94,038)	-4.45%

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

LIGHTING SERVICE

Description	Old Rate	New Rate
New 30' Wood Pole (Class 6) - Overhead	$4.34	$4.68
New 30' Metal or Fiberglass - Overhead	$8.66	$9.35
Existing Wood Pole - Underground	$2.18	$2.35
New 30' Wood Pole (Class 6) - Underground	$6.52	$7.04
New 30' Metal or Fiberglass - Underground	$10.81	$11.67
Wattage, per Watt	$0.051681	$0.060516
		0
Base Power Supply	$0.010113	$0.014535
PPFAC	-$0.002139	-11.144%

		Proration
New Rate Days	28	100%
Old Rate Days	0	0%

Total Days	28
Total kWh billed	150

Customer Bill	Current Rates	Proposed Rates	$Change	%Change
100 Watt	$5.17	$6.05	$0.88	17.02%
150 Watt	$7.75	$9.08	$1.33	17.16%
200 Watt	$10.34	$12.10	$1.76	17.02%
250 Watt	$12.92	$15.13	$2.21	17.11%
400 Watt	$20.67	$24.21	$3.54	17.13%
Existing Wood Pole OH	$4.34	$4.68	$0.34	7.83%
New 30' Wood Pole OH	$8.66	$9.35	$0.69	7.97%
New 30' Metal or FG OH	$2.18	$2.35	$0.17	7.80%
Existing Wood Pole UG	$6.52	$7.04	$0.52	7.98%
New 30' Wood Pole UG	$10.81	$11.67	$0.86	7.96%
New 30' Metal or FG UG	$0.05	$0.06	$0.01	17.10%
Base Power Supply	$1.52	$2.18	$0.66	43.42%
PPFAC	($0.32)	($0.24)	$0.08	-25.00%
Typical	$13.29	$15.70	$2.41	18.13%

Detail of Services Billed	Wattage	Units Billed
100 Watt	100	1
150 Watt	150	1
200 Watt	200	1
250 Watt	250	1
400 Watt	400	1
Existing Wood Pole OH		5
New 30' Wood Pole OH		0
New 30' Metal or FG OH		0
Existing Wood Pole UG		0
New 30' Wood Pole UG		0
New 30' Metal or FG UG		0

Exhibit CAJ-R-6

Clean

UNS Electric, Inc.
Transmission Cost Adjustor
Plan of Administration

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1. GENERAL DESCRIPTION

The purpose of the Transmission Cost Adjustor ("TCA") is to provide a mechanism to recover transmission costs associated with serving retail customers at the level approved by the Federal Energy Regulatory Commission ("FERC") at the same time as new transmission rates become effective for UNS Electric, Inc. ("UNS Electric" or "Company") transmission customers. UNS Electric shall make an annual filing with Docket Control that includes its revised TCA based on the Company's updated transmission service rates calculated pursuant to the Company's Open Access Transmission Tariff ("OATT"), including all supporting data and documentation used in calculating the formula rate ("Informational Filing") and the TCA. This Informational Filing shall be filed with the Commission no later than May 1.

The TCA applies to all UNS Electric Retail Electric Rate Schedules. For Standard Offer customers that are not demand billed, the TCA is applied to the bill as a monthly kWh charge. For Standard Offer customers that are demand billed, the TCA is applied as a kW charge. The charge and modifications to it will take effect in first billing cycle in June without proration.

UNS Electric's transmission service rates (the "Transmission Rates") are calculated annually in accordance with UNS Electric's formula rate. The formula rate calculation is specified within UNS Electric's OATT, as may be amended from time to time, as filed with and approved by FERC.

2. CALCULATIONS

The calculated Transmission Rates will be set forth in UNS Electric's Informational Filing. Transmission Rates are determined for the following classes:

Demand Billed Customers
Non-Demand Billed Customers

In addition to the Transmission Rate, UNS Electric will charge retail customers for other transmission-related services ("ancillary services") in accordance with its OATT ("Ancillary Services Rates") at such time that the Company provides these services. These additional ancillary services could include:

Scheduling, System Control and Dispatch Service

Regulation and Frequency Response Service
Energy Imbalance Service
Operating Reserve – Spinning Reserve Service
Operating Reserve – Supplemental Reserve Service

The total UNS Electric OATT rate is the sum of providing Transmission Rates and Ancillary Service Rates. The revenue requirement resulting from the UNS Electric OATT rate are collected by UNS Electric from its retail customers, partly in base rates and the remaining through the TCA rate. The table below is an example of the TCA calculation using the UNS Electric OATT rate in effect as of December 31, 20xx.

Line	Service Type		
		$/kWh	$/kW
		(A)	(B)
1.	Transmission Rate	$0.xxxx	$x.xxxx
2.	Scheduling	N/A	N/A
3.	Regulation and Frequency	N/A	N/A
4.	Energy Imbalance	N/A	N/A
5.	Spinning Reserve	N/A	N/A
6.	Supplemental Reserve	N/A	N/A
7.	Total	$0.xxxx	$x.xxxx
8.	Included in Retail Base Rates per OATT	$0.xxxx	$x.xxxx
9.	TCA (Line 7) – (Line 8)	$0.xxxx	$x.xxxx

UNS Electric's Transmission Rate shown on line 1 will change annually, whereas the Ancillary Rates shown on lines 2 through 6 will change only through a separate filing with FERC by UNS Electric.

3. ***FILING AND PROCEDURAL DEADLINES***

UNS Electric will file the Informational Filing, which includes the revised TCA and all supporting data and documentation used in calculating the formula rate with the Commission each year no later than May 1. The Commission Staff and interested parties shall have the opportunity to review UNS Electric's Informational Filing.

The new TCA rates proposed by UNS Electric shall be effective in first billing cycle in June unless Staff requests Commission review or otherwise ordered by the Commission. The TCA rates are not prorated.

UNS Electric, Inc.
Rates for Transmission Cost Adjustor For June 1, 20xx Through May 31, 20xx
Data For Period Ending December 31, 20xx

Line	Service Type		
		$/kWh	$/kW
		(A)	(B)
1	Transmission Rate	$x.xxxx	$x.xxxx
2	Scheduling	N/A	N/A
3	Regulation and Frequency	N/A	N/A
4	Energy Imbalance	N/A	N/A
5	Spinning Reserve	N/A	N/A
6	Supplemental Reserve	N/A	N/A
7	Total	$x.xxxx	$x.xxxx
8	Included in Retail Base Rates per OATT	$x.xxxx	$x.xxxx
9	TCA (Line 7) – (Line 8)	$x.xxxx	$x.xxxx

Redline

UNS Electric, Inc.
Transmission Cost Adjustor
Plan of Administration

Table of Contents

1. GENERAL DESCRIPTION

The purpose of the Transmission Cost Adjustor ("TCA") is to provide a mechanism to recover transmission costs associated with serving retail customers at the level approved by the Federal Energy Regulatory Commission ("FERC") at the same time as new transmission rates become effective for UNS Electric, Inc. ("UNS Electric" or "Company") transmission customers. UNS Electric shall make an annual filing with Docket Control that includes its revised TCA based on the Company's updated transmission service rates calculated pursuant to the Company's Open Access Transmission Tariff ("OATT"), including all supporting data and documentation used in calculating the formula rate ("Informational Filing") and the TCA. This Informational Filing shall be filed with the Commission no later than May 1.

The TCA applies to all UNS Electric Retail Electric Rate Schedules. For Standard Offer customers that are not demand billed, the TCA is applied to the bill as a monthly kWh charge. For Standard Offer customers that are demand billed, the TCA is applied as a kW charge. The charge and modifications to it will take effect in first billing cycle in June without proration.

UNS Electric's transmission service rates (the "Transmission Rates") are calculated annually in accordance with UNS Electric's formula rate. The formula rate calculation is specified within UNS Electric's OATT, as may be amended from time to time, as filed with and approved by FERC.

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The calculated Transmission Rates will be set forth in UNS Electric's Informational Filing. Transmission Rates are determined for the following classes:

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In addition to the Transmission Rate, UNS Electric will charge retail customers for other transmission-related services ("ancillary services") in accordance with its OATT ("Ancillary Services Rates") at such time that the Company provides these services. These additional ancillary services could include:

Scheduling, System Control and Dispatch Service

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Operating Reserve – Spinning Reserve Service
Operating Reserve – Supplemental Reserve Service

The total UNS Electric OATT rate is the sum of providing Transmission Rates and Ancillary Service Rates. The revenue requirement resulting from the UNS Electric OATT rate are collected by UNS Electric from its retail customers, partly in base rates and the remaining through the TCA rate. The table below is an example of the TCA calculation using the UNS Electric OATT rate in effect as of December 31, ~~2012~~20xx.

Line	Service Type		
		$/kWh	$/kW
		(A)	(B)
1.	Transmission Rate	$0.~~0059~~xxxx	$~~2.3022~~x.xxxx
2.	Scheduling	N/A	N/A
3.	Regulation and Frequency	N/A	N/A
4.	Energy Imbalance	N/A	N/A
5.	Spinning Reserve	N/A	N/A
6.	Supplemental Reserve	N/A	N/A
7.	Total	$0.~~0059~~xxxx	$~~2.3022~~x.xxxx
8.	Included in Retail Base Rates per OATT	$0.~~0059~~xxxx	$~~2.3022~~x.xxxx
9.	TCA (Line 7) – (Line 8)	$0.~~0000~~xxxx	$~~0.0000~~x.xxxx

UNS Electric's Transmission Rate shown on line 1 will change annually, whereas the Ancillary Rates shown on lines 2 through 6 will change only through a separate filing with FERC by UNS Electric.

3. ***FILING AND PROCEDURAL DEADLINES***

UNS Electric will file the Informational Filing, which includes the revised TCA and all supporting data and documentation used in calculating the formula rate with the Commission each year no later than May 1. The Commission Staff and interested parties shall have the opportunity to review UNS Electric's Informational Filing.

The new TCA rates proposed by UNS Electric shall be effective in first billing cycle in June unless Staff requests Commission review or otherwise ordered by the Commission. The TCA rates are not prorated.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

Rejoinder Testimony of

Craig A. Jones

on Behalf of

UNS Electric, Inc.

February 29, 2016

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Craig A. Jones and my business address is 88 East Broadway, Tucson Arizona, 85702.

Q. Did you file Direct or Rebuttal Testimony in this proceeding?

A. Yes.

Q. Which Commission Staff and/or Intervenor testimony do you address in your Rejoinder Testimony?

A. I will respond to the testimony of witnesses Quinn and Alston of Arizona Utility Ratepayer Alliance ("AURA"), witnesses Van Epps and Solganick of Staff, witness Higgins of Arizonans for Electric Choice and Competition and Noble Americas Energy Solution LLC ("AECC"), witness Yaquinto of Arizona Investment Council ("AIC"), witnesses Hendrix and Tillman of Wal-Mart, witness Zarnikau of Nucor Steel Corporation ("NUCOR"), witness Huber of Residential Utility Consumer Office ("RUCO"), witness Zwick of Arizona Community Action Association ("ACAA"), witness Wilson of Western Resource Advocates ("WRA"), and witness Schlegel of Southwest Energy Efficiency Project ("SWEEP"). Since many of these witnesses cover the same issues, in most cases I will refer to them collectively for ease of discussion.

Q. How is your Rejoinder Testimony organized?

A. In addition to this Introduction, Section II discusses the currently proposed allocation of revenues between the rate classes and the resulting rates as well as the related bill impacts. Section II will be based on the revised revenue requirement discussed by other Company witnesses in their Rejoinder Testimony. I also include revised Schedule H pages to reflect these revisions. Section III provides some comments related to the Company's CARES proposals and a modification to help address some parties' concerns about the impact on the lower use customers. In Section IV I will explain why the Company not only wishes to maintain its originally filed Buy-Through rate with all of its provisions, but that also, after reviewing all of the testimony, the Company now believes it should recover all of the generation costs in the last 3 years of its 4 year pilot offering by removing the 75% reduction to generation rates in years 2 through 4 of our original proposal. Section V will discuss Staff's proposal in its Surrebuttal Testimony to credit DG solar customers a mix of a 15% credit and a 15% incentive. Section VI will discuss a few miscellaneous issues from certain witnesses including requested revisions to the Lost Fixed Cost Recovery ('LFCR") Plan of Administration ("POA") and Transmission Cost Adjustment ("TCA") POA.

My Rejoinder Testimony addresses various witnesses and specifically a few items the Company does not agree with as presented in the various parties' Surrebuttal Testimony. My omission of any issue, either intentionally or unintentionally, in no way indicates the Company acquiesces to the other Party's position. Time constraints only allow a limited group of issues to be addressed in this Rejoinder Testimony. The Company reserves the right to address any other issues it deems unacceptable if it so chooses at a later time if necessary.

II. REVENUE ALLOCATION AND BILL IMPACTS

Q. Many of the parties have suggested the level of revenues recovered from the various classes should be more reflective of the proportions filed in the Company's original proposal instead of what was proposed in the Company's Rebuttal position. Would you like to speak to these requests?

A. Yes. The Company's original proposal, while certainly reasonable and acceptable, did allocate substantially more to the Residential class in an attempt to move cost recovery to a proportionally more equitable level between the rate classes based on the results of the Class Cost of Service Study ("CCOSS"). In a rate case, rate design and cost allocation are dynamic numbers. You start out with what you believe are reasonable numbers and blend in "gradualism" and "subsidy reduction" as well as other concepts as appropriate. This means that as the proceeding progresses and other parties' opinions are considered, sometimes your proposal evolves. In this case our proposal has evolved. After reviewing Staff's Direct position, blending in a reduction to the requested revenue requirement deficiency and adjustments to the base power costs, the Company modified its original position. The Company did not move fully to Staff's recommendation but did move toward their proposal. After considering the necessary facts, the Company reviewed how its changes impacted various customer's bills. Since the current CCOSS indicates the Residential classes should have a higher proportion of cost allocated to them, the Company allocated the revenue to the classes to produce either a decrease or a near neutral change to the Large Power Service ("LPS") rate classes, the Large General Service ("LGS") rate classes and the Medium General Service ("MGS") rate classes with larger increases going to Small General Service ("SGS"), Residential, Lighting and Interruptible rate classes. Please refer to **Exhibit CAJ-RJ-2** to see the H-1 through H-4 Schedules that have been updated to reflect the lower overall revenue requirement currently being requested by the Company. Schedule H-1 in this exhibit reflects the level of costs allocated to each general rate class.

The revised CCOSS uses the same allocation methods as the CCOSS originally filed by the Company in this proceeding. It was adjusted to reflect the lower overall revenue requirement being requested. The results still show that the rates being charged to the largest rate classes are producing revenues in excess of what the CCOSS indicates they should be responsible for, but due to gradualism and bill impact, the Company believes the results are reasonable at this time. More movement will be proposed in a subsequent rate case if the results still justify the adjustment.

A summary of the bill impacts resulting from the Company's proposed rates can be found in **Exhibit CAJ-RJ-1**. More detailed analysis of the bill impacts can be found in **Exhibit CAJ-RJ-2**. Schedule H-4 provides detailed bill impacts at various assumed usage levels for all rate classes. For both the Residential and SGS rate classes it also contains comparison of bill impacts resulting in the implementation of the proposed transitional rates the Company agreed to in its Rebuttal position (as adjusted to reflect the reduced revenue requirement) as well as the bill impacts of the three-part rates at those same usage levels. The calculations for the three-part rates assume a revenue neutral adjustment for the class as a whole, but will show varying impacts depending on the customer's volume of usage and load factor.

Exhibit CAJ-RJ-1 summarizes the results of Schedule H-4 for the primary rate classes and provides a bill impact calculation for each class' typical customer. For a typical Residential customer their bill will increase by approximately $4.82 per month on average which is an approximate 5.7% increase. An LPS customer's bill will generally increase by approximately 1%. Under the Company's current proposal the Residential and SGS customers will pay the transitional rates through the first quarter of 2017 at which point they will move to the new three-part rates. As mentioned above, by design the new three-part rates are to be revenue neutral for each primary rate class when compared to the transitional two-part rate. The change in rate design will result in bills changing by some amount, but that will vary by each individual customer's total usage and how they use their energy. For each of the individual classes, as a whole, changing to three-part rates will be revenue neutral. The various levels of bill impacts for residential and SGS customers are also reflected in **Exhibit CAJ-RJ-2** at pages 1 of 34 through page 22a of 43.

III. CARES

Q. A few of the parties have suggested the proposed three-part rates may impact low-income customers in a negative way and should be modified to protect this group of customers. Has the Company considered making any changes to the provisions offered to the CARES customers?

A. Yes. The Company wishes to modify its Rebuttal proposal and offer a flat discount amount to all CARES customers. This new proposal will increase the amount of discount to approximately $1.3 million per year, and will provide additional mitigation of bill impacts for the lower usage CARES customers. The Company continues to propose to recover the cost of the discount from the remaining residential customers.

Q. What is the Company proposing in your Rejoinder Testimony?

A. The Company now proposes a flat discount of $17 per month for CARES customers and a flat discount of $27 per month for the CARES-Medical (limited to prevent a negative bill). This has the added benefit of offsetting the only portion of the bill – the basic service charge – that the customer does not have the opportunity to change. The proposed $15 basic service charge will be more than offset for all CARES customers. In fact, based on test year data and the Company's proposed three-part rate design for nearly 3,000 CARES bills per year will be less than $10 under the proposed three-part rates. The three-part rate design will empower the customer to reduce their bill even more. They have control over how much they consume, how fast they consume it and when they consume it. As they become more educated through the use of a better rate design and the Company's educational programs, CARES customer will be able to reduce their bill even more.

Q. Please summarize the Company's proposal for the CARES customers.

A. The below table sets forth the current CARES discount, the transitional CARES discount, and the CARES discount under 3-part rates.

CARES Rates	Current	Transition	Proposed
Monthly Basic Service Charge	$4.90	$9.00	$15.00
Usage Discounts	30% 0-300 kWh	No change	N/A
	20% 301-600 kWh	No change	N/A
	10% 601-1000 kWh	No change	N/A
	Flat $8 > 1,000 kWh	No change	Flat $17
Average Bill Impact	N/A	$4.14	($0.23)

Q. Does the Company continue to oppose Ms. Zwick's proposal to expand the eligibility of CARES to more customers by increasing the percentage of the Federal poverty level?

A. Yes. The reasons are set forth in my Rebuttal Testimony. The current proposal is already providing approximately $1.3 million of benefits to CARES customers. The proposal to expand the CARES eligibility requirement would result in an additional cost shifts to other customers.

IV. BUY-THROUGH (AGS RIDER)

Q. Which Commission Staff and/or Intervenor parties addressed the Company's proposed Experimental Rider 14 – Alternative Generation Service (AGS) in Surrebuttal Testimony?

A. Staff, AECC, AIC, and Wal-Mart addressed proposed Experimental Rider 14 - AGS in Surrebuttal Testimony.

Q. Have you considered any changes to your original proposal as it relates to the AGS service the Company has proposed?

A. Yes, although the Company continues to oppose the buy-through rate, it is modifying its proposal because all parties appear to oppose shifting any cost recovery to other customers. The only practical way to ensure this is for the buy-through customer to pay the full retail rate with the exception of base power and PPFAC. Therefore the Company proposes to eliminate the discount in years 2-4.

Q. Do you have any comments on the Intervenor's Surrebuttal Testimonies with respect to the Company's proposed AGS Rider?

A. Yes. I am largely in agreement with the Surrebuttal Testimony of AIC witness Gary Yaquinto and will not address that testimony directly unless to rely on it for my comments on the other parties' positions. Staff witness Howard Solganick addresses the Company's proposed AGS Rider only to reiterate Staff's position that the AGS program should not impact any other customers and adds that if the AGS program is approved on a permanent basis, which the Company opposes, Staff recommends that the Company propose a market price for customers returning to utility service so as not to negatively impact other customers on the system.[1] To the recommendation of protecting other customers on the

[1] Staff Solganick Surrebuttal at 13:19-24 and 14:1-3.

system, the Company's position remains, as I stated in Rebuttal Testimony, that the Company does not support the AGS program and if it is approved in a form that results in lost revenues to the Company, those revenues should be eligible for recovery. The Company would consider other proposals, but the LFCR mechanism seems to be the most appropriate.[2] The Company believes that the issue of lost revenues should be addressed before anything like the proposed AGS program is adopted.

With respect to former AGS customers returning to utility service, the Company agrees with Staff. The AGS Rider as proposed states that the Company will provide returning customers with generation service at a market index price plus $20 per MWh until the Company is reasonably able to reintegrate them into the Company's generation planning and provide power at the applicable rate schedule. The length of this transition would be at the Company's determination, but no longer than one year.

Q. Please summarize Wal-Mart's Surrebuttal position regarding the Company's proposed Experimental Rider 14.

A. Wal-Mart witness Chris Hendrix essentially reiterated the same recommendations that he made in his Direct Testimony. Namely that the Company's proposed Experimental Rider 14 should be approved with several modifications related to the proposed management fee, participation requirements, participation limit, generation cost recovery, and program term.

Q. Do you have any comments on Wal-Mart's recommendations?

A. The Company addressed each of these proposed modifications sufficiently in Rebuttal and recommended their rejection. Wal-Mart has offered no further convincing evidence for adopting their recommendations in Surrebuttal Testimony. However, Mr. Hendrix makes

[2] Jones Rebuttal at 27:17-27 and 28:1-2.

some additional assertions to which the Company wishes to respond. These assertions relate to the program's eligibility requirements, participation limit, and term.

Q. Please address Wal-Mart's assertions regarding program eligibility.

A. Mr. Hendrix recommends in his Direct and Surrebuttal Testimony that all UNS Electric rate classes should be allowed to participate in the program. However, as I stated in my Rebuttal Testimony the Fortis acquisition settlement order that requires the Company to propose a buy-through tariff specifically designates only the Company's LPS class for inclusion in the program.[3] In his Surrebuttal Testimony, Mr. Hendrix argues that because the Company is proposing to move three Wal-Mart stores in the UNS Electric service area from the LPS rate class to the LGS rate class in this proceeding, Wal-Mart is being excluded from the program because of the proposed reclassification. However, the truth of the matter is that none of the three Wal-Mart facilities in the UNS Electric service area identified by Mr. Hendrix would meet the program's minimum 2,500 kW load threshold requirement for participation regardless of rate classification in the absence of load aggregation, which the Company opposes.[4]

Q. Please address Wal-Mart's claims with respect to the program participation limit.

A. In his Direct and Surrebuttal Testimony Mr. Hendrix has proposed that the total program participation limit be raised from the Company's proposed 10 MW of total customer load to 150 MW. Furthermore, in his Surrebuttal Testimony Mr. Hendrix asserts the following:

> The Company does not seem to understand that my increased cap proposal is to supplant the market power purchases in the future. Since the Company is buying power on the open market, the AGS Program with my increased

[3] UNSE Jones Rebuttal at 47:12-19.
[4] UNSE Jones Rebuttal at 46:22.

cap of 150 MW is replacing the Company's own wholesale market purchases with those of the Customers participating in AGS.[5]

Q. Do you agree that the Company did not understand Wal-Mart's rationale for its recommendation?

A. No. The Company fully understands Wal-Mart's rationale for its recommendation. As I stated in my Rebuttal Testimony, an Integrated Resource Plan (IRP) is a utility process for meeting forecasted annual peak and energy demand, plus an established reserve margin, through a combination of supply-side and demand-side resources over a specified future period. It is a dynamic process and a utility's IRP will typically be examined, modified, and acknowledged in a proceeding before a regulatory commission. Far from existing in isolation, a utility's supply-side resources, namely utility-owned generation and power market purchases in this case, are highly interdependent. A utility will optimize its planning and use of these supply-side resources to minimize system costs to the benefit of all customers on the system. Utility flexibility in this process is vital and the loss of any optionality is detrimental to the utility's efforts. Wal-Mart is proposing that a small group of customers be allocated approximately 85% of the Company's purchased power market opportunities[6] to their benefit only, not for the benefit of the vast majority of customers on the system.

Finally, the utility obligation to serve is a long-term endeavor. This small group of customers with no utility obligation to serve would reap the benefits of a relatively soft power market while those benefits currently flow through to all UNS Electric customers. How long would AGS participants be willing to take on these responsibilities if the power market were to rebound and market prices approach and exceed utility service? Mr. Hendrix's proposal clearly underestimates the difficulties associated with reintegrating 150

[5] Wal-Mart Hendrix Surrebuttal at 5:14-18.
[6] UNSE Sheehan Direct at 12.

MW of load, approximately 35% of current planning requirements,[7] back into the UNS Electric system.

Q. **What are Mr. Hendrix's recommendations for the program term?**

A. Mr. Hendrix objects to tagging the program as "Experimental" or "Pilot" and seems to recommend against the proposed 4-year program term. Although Mr. Hendrix does not propose an alternative to 4 years in his Surrebuttal, in Direct Testimony Mr. Hendrix recommended that there should be no limit on the term of the program.[8]

Q. **What rationale does Mr. Hendrix give for an unlimited program term?**

A. Mr. Hendrix argues that a testing and evaluation period is unnecessary because evidence shows that programs of this type have been effective in Arizona and other jurisdictions. He points to the APS AG-1 program in Arizona as evidence of this. However, in evidence provided in this docket APS has estimated that it has experienced a net loss from its AG-1 program since inception to May 2015 of approximately $16.8 million.[9] This evidence supports the Company's proposal that if ordered to offer AGS in any form, the program term should be limited to 4 years after which a full program evaluation should be performed.

Q. **Do you wish to address AECC's Surrebuttal position regarding the Company's proposed Experimental Rider 14?**

A. No. My responses to Wal-Mart and AIC's Rebuttal of Mr. Higgins cover the key issues I would have addressed.

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[7] UNSE Sheehan Direct at 2:16.
[8] Wal-Mart Hendrix Direct at 9:2.
[9] AIC Data Request, AIC 1.1.

V. STAFF'S PROPOSED DG SOLAR BILL CREDIT AND INCENTIVE

Q. In Staff witness Broderick's Surrebuttal Testimony he proposes a 15% bill credit for DG customers before June 1, 2015[10] and a 15% cost per kW incentive for DG solar installations for the first six months following the completion of the full transition from two-part rates to three-part rates[11]. Do you wish to express any thoughts on this proposal?

A. The Company believes this proposal is designed as a transitional option for DG solar customers to address many of the concerns expressed in various parties' testimonies in this proceeding. In his testimony, Mr. Broderick also mentions the cost of the credits and incentives could be recovered through a special surcharge or through REST funds[12]. The Company does not believe the proposed three-part rate is overly burdensome on the partial requirements customers, but understands a desire to create a more gradual transition especially if pre-June 1, 2015 DG solar customer are not allowed to be grandfathered onto a two-part rate. In the event the Commission allows pre-June 1, 2015 DG solar customers to be grandfathered to a two-part rate it is the Company's opinion that the 15% bill credit for those customers would not be necessary. However, if the Commission approves Staff's and the Company's three-part rate design for all DG customers, the Company believes that the cost of any bill credit should be recovered through the REST. The Company is of the opinion that this type of credit is better addressed in the REST in order to evaluate its merits as it relates to REST compliance.

The Company estimates such a discount will result in a total credit amount of approximately $135,000 per year (1,500 pre 6/1/15 DG customers at an average of $50 per month of total bill after moving to a three part rate, multiplied by 15% and multiplied by

[10] Staff Broderick Surrebuttal at 6:2-9.
[11] Staff Broderick Surrebuttal at 14:2-4.
[12] Staff Broderick Surrebuttal at 6:5 and 14:7.

12 months per year) that would be recovered from all customers through the REST. As stated above if Staff's proposal is accepted by the Commission, the Company prefers the REST option as the method of recovery as it gives transparency to the discount.

Q. Does the Company support Staff's proposal for post-June 1, 2015 DG customers??

A. No. The Company does not agree with Staff's proposal relating to the 15% cost per kW incentive for DG solar installations. It is the Company's position that this portion of the proposal is not necessary and should not be approved. However, if the Commission determines that post-June 1, 2015 DG customers receive incentives, the Company proposes using a method that is consistent with the 15% bill credit proposed for the pre-June 1, 2015 DG solar customers.

Q. Why does the Company wish to recommend changes to Staff's proposal as it relates to post-June 1, 2015 if the Commission accepts it?

A. The reasons the Company would like to modify the proposal for the post June 1, 2015 DG solar customer are threefold. The key concerns the Company identified as needing to be changed are:

1) at minimum, a flat $/kW with a cap on the total incentive amount would be necessary to avoid creating an incentive to create artificially high pricing of equipment and proposed oversizing of the system;

2) the number of applications in that six-month window would likely sky rocket because there are no utility incentives currently available and installers would want to maximize installation falling within the window of time an incentive is offered. This could result in installations doubling or even tripling during that window and;

3) the proposal appears to create a "dead-band". Customers installing facilities during the interim period from June 1, 2015 through an estimated three-part rate implementation date proposed to be in the first quarter of March 2017 would get nothing.

Additionally, if the incentive is paid on a percentage of cost per kW of the installed unit, the cost during that 6-month window will be substantial. If a solar unit costs approximately $3 per watt, a 7 kW system would have an installed cost of approximately $21,000, which would produce a one-time incentive payment of approximately $3,150 (15% of $21,000). Currently the pace of installation in the UNS Electric territory is about 25 units a month. During the six month window a total incentive payment of approximately $472,500 would be created that year. That is at the non-incentive pace of installations. If the pace increases substantially, that amount could exceed $1,000,000 very easily.

Again, the Company believes that any incentives for post June 1, 2015 DG customers should be addressed in the Company's REST Plan following the implementation of three-part rates.

VI. MISCELLANEOUS ISSUES

Q. What other items would you like to address?

A. Staff witness Broderick indicated he would like to see a revised POA for the LFCR.[13] The Company does not oppose providing a revised LFCR POA, but believes it would be premature to do so at this time. The current LFCR POA is generally reflective of Staff's overall proposal in this proceeding (may need to be modified to exclude fixed charge option references). It would need to be modified after the final Order of the Commission to

[13] Staff Broderick Surrebuttal at 11:1.

reflect any revisions to rate design, added rate categories and the new rates, but that will not be known until after the final Order. The Company has already submitted as part of its direct case a LFCR POA that adds back to the LFCR rates an amount to reflect lost fixed costs associated with generation and the other 50% of the demand charges, along with other changes including the blending of the rate into one percentage adjustment and increasing the cap. The Company's POA would also need to be updated to reflect the final Order of the Commission if it agrees to allow the Company to recover all of its lost fixed cost, including generation and the demand related costs. All of these revisions would be more appropriately addressed as part of the Company's compliance filing subsequent to the Commission's final Order. The Company has no objection to providing Staff an early version for their review if time allows.

Staff witness Van Epps also requested that the Company add language or a work paper that more precisely define the TCA calculation process.[14] The Company is agreeable to working with Staff to document what the Company believes is a common understanding of what the TCA calculation process is and provide it to Staff before the end of the hearing to assure they agree with the process as documented. Once we have created a final document, the Company proposes that it be submitted as part of the compliance filing subsequent to the final Order in this proceeding.

Q. Does this conclude your Testimony?

A. Yes, it does.

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[14] Staff Van Epps Surrebuttal 2:22-24.

Exhibit CAJ-RJ-1

Exhibit CAJ-RJ-1

UNS Electric Inc.
Bill Impacts
Test Period Ending December 31, 2014

Line No.	Class Description	Customer Counts To-date (Dec 2015)	New Summer Month A	Total Summer Change B	Summer Change C=(B*6)	New Winter Month D	Total Winter Change E	Winter Change F=(E*6)	Annual Bill G=(A*6+D*6)	TEST YEAR ADJUSTED WITH MARGIN INCREASE, FUEL/PPAFC TRUE-UP AND TCA: Annual Bill Change	Monthly Bill Change	Percent Change to Total Bill With Fuel Increase	COS RETURNS
1	Residential Current to Transition	75,504	$104.60	$4.40	$26.39	$74.72	$5.24	$31.45	$1,075.95	$57.84	$4.82	5.68%	
2	Residential Transition to Demand		$107.84	$3.24	$19.43	$74.39	($0.33)	($2.00)	$1,093.38	$17.43	$1.45	1.62%	
3	Residential Current to Demand		$107.84	$7.64	$45.82	$74.39	$4.91	$29.45	$1,093.38	$75.27	$6.27	7.39%	
4	Residential CARES - Current to Transition	5,904	$77.86	$4.37	$26.22	$57.60	$3.91	$23.46	$812.75	$49.68	$4.14	6.51%	
5	Residential CARES Transition to Demand		$79.85	$2.31	$13.86	$54.84	($2.76)	($16.56)	$808.14	($2.70)	($0.23)	-0.33%	
6	Residential CARES Current to Demand		$79.85	$6.68	$40.06	$54.84	$1.15	$6.90	$808.14	$46.98	$3.92	6.17%	6.55%
7	Residential CARES-M Current to Transition	251	$95.32	$4.48	$26.88	$69.54	$3.90	$23.38	$989.14	$50.26	$4.19	5.35%	
8	Residential CARES-M Transition to Demand		$100.02	$5.09	$30.54	$64.26	($5.28)	($31.68)	$985.68	($1.14)	($0.10)	-0.12%	
9	Residential CARES-M Current to Demand		$100.02	$9.58	$57.48	$64.26	($1.37)	($8.22)	$985.68	$49.26	$4.11	5.26%	
10	Residential TOU	266	$127.07	$8.47	$50.80	$84.34	$5.34	$32.04	$1,268.46	$82.84	$6.90	6.99%	
11	Residential TOU Super Peak	5	$125.50	$8.16	$48.94	$84.26	$9.64	$57.84	$1,258.56	$106.78	$8.90	9.27%	
12	Small General Service Current to Transition	8,839	$145.07	$9.38	$56.30	$117.41	$10.90	$65.39	$1,574.88	$121.69	$10.14	8.37%	
13	Small General Service Transition to Demand		$147.72	$2.65	$15.91	$118.50	$1.09	$6.55	$1,597.32	$22.46	$1.87	1.43%	
14	Small General Service Current to Demand		$147.97	$12.28	$73.69	$118.70	$12.18	$73.11	$1,600.02	$146.80	$12.23	10.10%	6.23%
15	Small General Service TOU	14	$245.40	$13.02	$78.10	$174.56	$14.12	$84.71	$2,519.76	$162.81	$13.57	6.91%	
16	Interruptible Service	25	$9,142.83	$875.25	$5,251.49	$6,938.55	$661.82	$3,970.93	$96,488.28	$9,222.42	$768.54	10.57%	
17	Medium General Service	1279	$3,081.61	$35.27	$211.62	$2,425.66	$38.51	$231.04	$33,043.60	$442.66	$36.89	1.36%	
18	Medium General Service TOU	9	$7,119.98	($120.16)	($720.96)	$6,496.26	$227.41	$1,364.46	$81,697.44	$643.50	$53.63	0.79%	18.30%
19	Large General Service	10	$28,354.74	($445.25)	($2,671.48)	$28,354.74	($445.25)	($2,671.48)	$340,256.88	($5,342.96)	($445.25)	-1.55%	
20	Large General Service (Formally LPS)	7	$40,649.16	($1,721.36)	($10,328.13)	$40,649.16	($1,721.36)	($10,328.13)	$487,789.92	($20,656.26)	($1,721.36)	-4.06%	
21	Large General Service TOU	2	$58,778.38	($332.07)	($1,992.42)	$54,340.61	$1,338.29	$8,029.74	$678,713.94	$6,037.32	$503.11	0.90%	
22	Large Power Service	4	$113,504.35	$1,198.74	$7,192.45	$113,504.35	$1,198.74	$7,192.45	$1,362,052.20	$14,384.90	$1,198.74	1.07%	
23	Large Power Service TOU	0	$188,146.50	$3,250.24	$19,501.44	$167,697.86	$677.25	$4,063.50	$2,135,066.16	$23,564.94	$1,963.75	1.12%	18.42%
24	Lighting Service	1,922	$15.33	$2.04	$12.24	$15.33	$2.04	$12.24	$183.96	$24.48	$2.04	15.35%	8.73%

Exhibit CAJ-RJ-2

UNS Electric, Inc.
Summary of Revenues by Customer Classifications
Adjusted Present Rates And Proposed Rates
Test Period Ended December 31, 2014

Line No.	Class of Service	Test Year Present Net Revenue	Net Change	Proposed % Increase to Test Year	Adjusted TY Revenue	Proposed Dollar Increase (a)	Proposed Percent Increase to Adjusted Test Year Revenues (a)	Proposed Net Revenue
1	Residential Service	$83,768,709	$8,380,673	10.0%	$78,169,265	$14,136,082	18.08%	$92,305,348
2	Small General Service	12,922,488	1,067,025	8.3%	12,461,200	1,528,313	12.26%	13,989,513
3	Interruptible Power Service	2,920,047	108,956	3.7%	3,111,532	-82,529	-2.65%	3,029,003
4	Medium General Serive	0	43,784,304	0.0%	0	43,784,304	0.0%	43,784,304
5	Large General Service	46,292,475	-36,705,909	-79.3%	43,498,604	-33,905,841	-77.95%	9,592,763
6	Large Power Service	21,454,373	-14,846,030	-69.2%	17,170,623	-10,483,155	-61.05%	6,687,468
7	Lighting	528,359	71,219	13.5%	546,954	52,625	9.62%	599,578
8	Subtotal	$167,886,452	$1,860,238	1.11%	$154,958,178	$15,029,800	9.70%	$169,987,977
9	Other Operating Revenue	1,734,044	95,034	N/A	1,829,078	N/A	N/A	1,829,078
10	Total	$169,620,496	$1,955,272	1.15%	$156,787,255	$15,029,800	9.59%	$171,817,055

Total Electric Retail Service	Recap Schedules
(a) H-2 (P2)	A-1

(b) Total increase is $69,916 less than Schedule A1, Line 10 due to difference from Test Year billed to booked revenues

UNS Electric, Inc.
Comparisons of Sales by Rate Schedules
Present And Proposed Rates
Test Period Ended December 31, 2014

Line No.	Class of Service	Rate Schedule Present	Proposed[1]	Actual kWh Sales	Actual Average Number of Customers	Actual Average kWh per Customer	Test Year End Sales Adjustments	Adjusted kWh Sales	Adjusted Average Number of Customers	Adjusted Average Sales per Customer	Tariff Changes kWh Sales	Tariff Changes Average Number of Customers	Tariff Changes Average Sales per Customer
1	Residential Cares	CARES	NC	57,138,737	6,112	9,349	1,701,588	58,840,325	6,236	9,436	58,840,325	6,236	9,436
2	Residential Service	RES-01	NC	755,005,617	75,847	9,954	6,209,782	761,215,400	76,035	10,011	761,215,400	76,035	10,011
3	Residential Service TOU	RES-TOU	NC	2,731,217	230	11,892	321,911	3,053,127	257	11,880	3,053,127	257	11,880
4	Res Bright Community Solar	RES-BC	NC	844,333	79	10,733	0	844,333	79	10,733	844,333	79	10,733
5	Residential Unbilled			(484,060)	0			0	0		0	0	
6	Small General Service	SGS-10	NC	118,754,401	8,704	13,643	(253,035)	118,501,366	8,750	13,543	118,501,366	8,750	13,543
7	Small General Service TOU	SGS-TOU	NC	170,628	8	22,750	11,802	182,430	8	22,804	182,430	8	22,804
8	Interruptible Power Service	IPS	NC	38,106,302	32	1,193,931	(2,538,461)	35,567,841	29	1,226,477	35,567,841	29	1,226,477
9	Medium General Service		MGS	0	0	0	0	0	0	0	408,462,296	1,331	306,884
10	Medium General Service TOU		MGS-TOU	0	0	0	0	0	0	0	7,718,956	8	964,869
11	Large General Service	LGS	LGS	448,678,574	1,361	329,688	(2,896,080)	445,782,493	1,341	332,425	95,412,304	17	5,612,488
12	Large General Service TOU	LGS-TOU	LGS TOU	3,834,211	5	821,617	3,884,745	7,718,956	8	964,869	15,418,264	2	7,709,132
13	LGS Bright Community Solar	LGS-BC	MGSBC	16,769	3	5,590	(16,769)	0	0	0	0	0	0
14	Large General Service Unbilled			384,473	0			0	0		0	0	
15	Large Power Service & TOU <69 kV	LPS/LPS TOU	LGS/LGS TOU	92,705,606	12	7,672,188	(19,195,235)	73,510,371	9	8,167,819	0	0	0
16	LPS Standard/Mining & TOU >69 kV	LPS/LPSM/ LPS TOU	NC	157,107,744	6	26,184,624	(64,342,470)	92,765,274	4	23,191,318	92,765,274	4	23,191,318
17	Large Power Service Unbilled			(369,148)	0			0	0		0	0	
18	Lighting	LTG	NC	2,820,013	2,388	1,181	7,237	2,827,250	2,388	1,184	2,827,250	2,388	1,184
19	Total Electric Retail Service			1,677,445,418	94,785	17,697	(77,104,986)	1,600,809,167	95,144	16,825	1,600,809,167	95,144	16,825

Note:
[1] NC equals No Change

UNS Electric, Inc.
Comparisons of Revenues by Rate Schedules
Present And Proposed Rates
Test Period Ended December 31, 2014

Line No.	Class of Service	Proposed	Unadjusted [1] Margin Revenue	Unadjusted [2] Fuel & PPFAC Revenue	Margin Pro Forma Adjustment	Fuel & PPFAC [3] Pro Forma Adjustment	Adjusted Margin Revenue	Adjusted Fuel & PPFAC Revenue	Adjusted TY Revenues	Proposed Revenue	Proposed Increase To TY Revenue $	Proposed Increase To TY Revenue %	Proposed Increase to Adjusted Revenue [4] $	Proposed Increase to Adjusted Revenue [4] %
1	Residential Cares	RES-01	$1,779,128	$3,029,378	$14,612	($444,219)	$1,793,740	$2,585,159	$4,378,898	$5,352,853	$544,347	11.32%	$973,954	18.20%
2	Residential Service	RES-01	31,759,612	46,999,721	-289,767	-5,063,987	31,469,845	41,935,733	73,405,578	86,527,437	7,768,105	9.86%	13,121,859	15.16%
3	Residential Service TOU	RES-TOU	116,271	152,725	11,729	16,811	128,000	169,535	297,536	323,404	54,408	20.23%	25,869	8.00%
4	Res Bright Community Solar	RES-BC	34,190	53,651	-588	0	33,602	53,651	87,253	101,654	13,813	15.72%	14,401	14.17%
5	Residential Unbilled		110,955	-266,920	-110,955	266,920	0	0	0	0	0	0.00%	0	0.00%
6	Small General Service	SGS-10	6,255,704	6,650,173	-128,102	-335,235	6,127,602	6,314,938	12,442,540	13,970,043	1,064,166	8.25%	1,527,503	10.93%
7	Small General Service TOU	SGS-TOU	8,527	8,085	465	1,583	8,992	9,668	18,660	19,470	2,859	17.21%	810	4.16%
8	Interruptible Power Service	IPS	1,335,391	1,584,656	-112,156	303,640	1,223,235	1,888,297	3,111,532	3,029,003	108,956	3.73%	(82,529)	-2.72%
9	Medium General Service	MGS	0	0	0	0	0	0	0	43,140,732	43,140,732	n/a	43,140,732	100.00%
10	Medium General Service TOU	MGS-TOU	0	0	0	0	0	0	0	643,573	643,573	n/a	643,573	100.00%
11	LGS Bright Community Solar	LGS-BC	898	976	-898	-976	0	0	0	0	0	0.00%	0	0.00%
12	Large General Service	LGS	21,574,476	24,416,757	-471,036	-2,649,801	21,103,440	21,766,956	42,870,396	8,246,263	(37,744,970)	-82.07%	(34,624,133)	-419.88%
13	Large General Service TOU	LGS - TOU	121,380	186,059	133,252	187,517	254,632	373,576	628,208	1,346,500	1,039,061	337.97%	718,292	53.35%
14	General Service Unbilled		138,446	-146,516	-138,446	146,516	0	0	0	0	0	0.00%	0	0.00%
15	Large Power Service & LPS TOU <69 kV	LPS <69	5,072,348	3,652,261	-1,258,960	2,258,222	3,813,388	5,910,483	9,723,871	0	(8,724,609)	-100.00%	(9,723,871)	0.00%
16	Large Power Service Unbilled		-31,928	-47,197	31,928	47,197	0	0	0	0	0	0.00%	0	0.00%
17	Large Power Service & LPS TOU >69 kV	LPS >69	6,894,832	5,914,057	-3,702,992	-1,659,144	3,191,840	4,254,913	7,446,752	6,687,468	(6,121,421)	-47.79%	(759,284)	-11.35%
18	Lighting	LTG	505,944	22,415	0	18,594	505,944	41,009	546,954	599,578	71,219	13.48%	52,625	8.78%
19	Total Electric Service		$75,676,172	$92,210,280	-$6,021,912	-$6,906,362	$69,654,260	$85,303,918	$154,958,178	$169,987,977	$1,860,238	1.11%	$15,029,800	9.70%

Note:
[1] Test Year Billed Margin Revenues calculated $69,916 more than Booked Revenues.
[2] Test Year Billed Fuel and PPFAC revenues calculated $175,930 less than Booked Revenues.
[3] Test Fuel and PPFAC Test Year True-up includes a Billed to Book adjustment of $175,930.
[4] Total increase is $69,916 less than Schedule A1, Line 10 due to difference from Test Year billed to booked revenues.

	Present Rate	Proposed Rate	Increase $	Increase %
Residential Service - CARES - *Transition Rates*				
Basic Service Charge	$4.90	$9.00	$4.10	83.67%
Energy Charge 1st 400 kWhs	$0.018973	$0.028700	$0.009727	51.27%
Energy Charge, all additional kWhs	$0.035400	$0.048100	$0.012700	35.88%
Base Power Supply Charge, all kWhs	$0.061700	$0.050260	-$0.011440	-18.54%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Residential Service CARES Demand				
Basic Service Charge	N/A	$15.00	N/A	N/A
Demand Charge, per kW	N/A	$5.00	N/A	N/A
Energy Charge (kWhs)	N/A	$0.015340	N/A	N/A
Base Power Supply Charge, Summer On-Peak all kWhs	N/A	$0.105800	N/A	N/A
Base Power Supply Charge, Summer Off-Peak all kWhs	N/A	$0.042830	N/A	N/A
Base Power Supply Charge, Winter On-Peak all kWhs	N/A	$0.086300	N/A	N/A
Base Power Supply Charge, Winter Off-Peak all kWhs	N/A	$0.038610	N/A	N/A
PPFAC[1]	N/A	$0.000000	N/A	N/A
Residential Service - *Transition Rates*				
Basic Service Charge	$10.00	$15.00	$5.00	50.00%
Energy Charge 1st 400 kWhs	$0.019300	$0.030100	$0.010800	55.96%
Energy Charge 401-1,000 kWhs	$0.034350	$0.040100	$0.005750	16.74%
Energy Charge, all additional kWhs	$0.038499	$0.058100	$0.019601	50.91%
Base Power Supply Charge, all kWhs	$0.064510	$0.055090	-$0.009420	-14.60%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Residential Service Time-of-Use - *Transition Rates*				
Basic Service Charge	$11.50	$15.00	$3.50	30.43%
Energy Charge 1st 400 kWhs	$0.030350	$0.035300	$0.004950	16.31%
Energy Charge 401-1,000 kWhs	$0.030350	$0.035300	$0.004950	16.31%
Energy Charge, all additional kWhs	$0.030350	$0.035300	$0.004950	16.31%
Base Power Supply Charge, Summer On-Peak all kWhs	$0.129605	$0.111001	-$0.018604	-14.35%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.039605	$0.042830	$0.003225	8.14%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.129605	$0.091550	-$0.038055	-29.36%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.031385	$0.038610	$0.007225	23.02%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Residential Service Demand				
Basic Service Charge	N/A	$15.00	N/A	N/A
Demand Charge, per kW	N/A	$5.00	N/A	N/A
Energy Charge (kWhs)	N/A	$0.015340	N/A	N/A
Base Power Supply Charge, Summer On-Peak all kWhs	N/A	$0.105800	N/A	N/A
Base Power Supply Charge, Summer Off-Peak all kWhs	N/A	$0.042830	N/A	N/A
Base Power Supply Charge, Winter On-Peak all kWhs	N/A	$0.086300	N/A	N/A
Base Power Supply Charge, Winter Off-Peak all kWhs	N/A	$0.038610	N/A	N/A
PPFAC[1]	N/A	$0.000000	N/A	N/A
Residential Service Time-of-Use Super Peak - *Transition Rates*				
Basic Service Charge	$11.50	$15.00	$3.50	30.43%
Energy Charge 1st 400 kWhs	$0.025000	$0.030100	$0.005100	20.40%
Energy Charge, all additional kWhs	$0.035000	$0.040100	$0.005100	14.57%
Base Power Supply Charge, Summer On-Peak all kWhs	$0.170000	$0.159790	-$0.010210	-6.01%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.039700	$0.040810	$0.001110	2.80%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.150000	$0.159790	$0.009790	6.53%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.038700	$0.040810	$0.002110	5.45%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%

	Present Rate	Proposed Rate	Increase $	Increase %
Small General Service - *Transition Rates*				
Basic Service Charge	$14.50	$30.00	$15.50	106.90%
Energy Charge 1st 400 kWh	$0.030176	$0.030000	-$0.000176	-0.58%
Energy Charge 401 -7,500 kWh	$0.041042	$0.039900	-$0.001142	-2.78%
Energy Charge >7,500 kWh	$0.076042	$0.077300	$0.001258	1.65%
Base Power Supply Charge, all kWhs	$0.058241	$0.053290	-$0.004951	-8.50%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Small General Service Demand				
Basic Service Charge	N/A	$30.00	N/A	N/A
Demand Charge, per kW	N/A	$5.05	N/A	N/A
Energy Charge (kWhs)	N/A	$0.015970	N/A	N/A
Base Power Supply Charge, Summer On-Peak all kWhs	N/A	$0.097800	N/A	N/A
Base Power Supply Charge, Summer Off-Peak all kWhs	N/A	$0.045800	N/A	N/A
Base Power Supply Charge, Winter On-Peak all kWhs	N/A	$0.096800	N/A	N/A
Base Power Supply Charge, Winter Off-Peak all kWhs	N/A	$0.040036	N/A	N/A
PPFAC[1]	N/A	$0.000000	N/A	N/A
Small General Service Time-of-Use - *Transition Rates*				
Basic Service Charge	$16.50	$30.00	$13.50	81.82%
Energy Charge 1st 400 kWh	$0.030176	$0.030000	-$0.000176	-0.58%
Energy Charge 401 -7,500 kWh	$0.043176	$0.039900	-$0.003276	-7.59%
Energy Charge >7,500 kWh	$0.076042	$0.077300	$0.001258	1.65%
Base Power Supply Charges				
Base Power Supply Charge, Summer On-Peak all kWhs	$0.129605	$0.109800	-$0.019805	-15.28%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.039605	$0.045800	$0.006195	15.64%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.129605	$0.108800	-$0.020805	-16.05%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.031385	$0.040036	$0.008651	27.56%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Small General Service Demand Time-of-Use				
Basic Service Charge	N/A	$30.00	N/A	N/A
Demand Charge, per kW	N/A	$5.05	N/A	N/A
Energy Charge (kWhs)	N/A	$0.015970	N/A	N/A
Base Power Supply Charge, Summer On-Peak all kWhs	N/A	$0.097800	N/A	N/A
Base Power Supply Charge, Summer Off-Peak all kWhs	N/A	$0.045800	N/A	N/A
Base Power Supply Charge, Winter On-Peak all kWhs	N/A	$0.096800	N/A	N/A
Base Power Supply Charge, Winter Off-Peak all kWhs	N/A	$0.040036	N/A	N/A
PPFAC[1]	N/A	$0.000000	N/A	N/A
Medium General Service[2]				
Basic Service Charge	$50.00	$100.00	$50.00	100.00%
Demand Charge, per kW	$12.81	$13.47	$0.66	5.15%
Energy Charge (kWhs)	$0.005470	$0.005480	$0.000010	0.18%
Base Power Supply Charge, all kWhs	$0.056603	$0.053290	-$0.003313	-5.85%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Medium General Service Time-of-Use[2]				
Basic Service Charge	$52.00	$100.00	$48.00	92.31%
Demand Charge, per kW	$12.81	$13.47	$0.66	5.15%
Energy Charge (kWhs)	$0.005470	$0.005480	$0.000010	0.18%
Base Power Supply Charge, Summer On-Peak all kWhs	$0.114886	$0.114886	$0.000000	0.00%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.039886	$0.033500	-$0.006386	-16.01%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.114886	$0.101047	-$0.013839	-12.05%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.026168	$0.031690	$0.005522	21.10%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%

	Present Rate	Proposed Rate	Increase $	Increase %
Large General Service				
Basic Service Charge	$50.00	$300.00	$250.00	500.00%
Demand Charge, per kW	$12.81	$12.88	$0.07	0.55%
Energy Charge (kWhs)	$0.005470	$0.005300	-$0.000170	-3.11%
Base Power Supply Charge, all kWhs	$0.056603	$0.053290	-$0.003313	-5.85%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Large General Service Time-of-Use				
Basic Service Charge	$52.00	$300.00	$248.00	476.92%
Demand Charge, per kW	$12.81	$12.88	$0.07	0.55%
Energy Charge (kWhs)	$0.005470	$0.005300	-$0.000170	-3.11%
Base Power Supply Charge, Summer On-Peak all kWhs	$0.114886	$0.143771	$0.028885	25.14%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.039886	$0.038600	-$0.001286	-3.22%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.114886	$0.139880	$0.024994	21.76%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.026168	$0.034927	$0.008759	33.47%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Large Power Service[3]				
Basic Service Charge <69 kV	$1,200.00	$300.00	-$900.00	-75.00%
Basic Service Charge ≥69 kV	$1,200.00	$1,500.00	$300.00	25.00%
Demand Charge <69kV, per kW	$22.00	$12.88	-$9.12	-41.45%
Demand Charge ≥69kV, per kW	$17.00	$12.48	-$4.52	-26.59%
Energy Charge (kWhs) <69 kV	$0.000462	$0.005300	$0.004838	1047.19%
Energy Charge (kWhs) ≥69 kV	$0.000462	$0.000500	$0.000038	8.23%
Base Power Supply Charge, all kWhs <69 kV	$0.041880	$0.053290	$0.011410	27.24%
Base Power Supply Charge, all kWhs ≥69 kV	$0.000000	$0.049332	$0.049332	#DIV/0!
PPFAC[1] <69kV	($0.002139)	$0.000000	$0.002139	100.00%
PPFAC[1] ≥69kV	($0.002139)	$0.000000	$0.002139	100.00%
Large Power Service Time-of-Use[3]				
Basic Service Charge <69 kV	$1,200.00	$300.00	-$900.00	-75.00%
Basic Service Charge ≥69 kV	$1,200.00	$1,500.00	$300.00	25.00%
Demand Charge <69kV, per kW	$22.00	$12.88	-$9.12	-41.45%
Demand Charge ≥69kV, per kW	$17.00	$12.48	-$4.52	-26.59%
Energy Charge (kWhs) <69 kV	$0.000462	$0.005300	$0.004838	1047.19%
Energy Charge (kWhs) ≥69 kV	$0.000462	$0.000500	$0.000038	8.23%
Base Power Supply Charge <69 kV				
Base Power Supply Charge, Summer On-Peak all kWhs	$0.123580	$0.143771	$0.020191	16.34%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.024716	$0.038600	$0.013884	56.17%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.093880	$0.139880	$0.046000	49.00%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.022105	$0.034927	$0.012822	58.00%
Base Power Supply Charge ≥69 kV				
Base Power Supply Charge, Summer On-Peak all kWhs	$0.123580	$0.125200	$0.001620	1.31%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.024716	$0.033410	$0.008694	35.18%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.093880	$0.092110	-$0.001770	-1.89%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.022105	$0.030410	$0.008305	37.57%
PPFAC[1] <69kV	($0.002139)	$0.000000	$0.002139	100.00%
PPFAC[1] ≥69kV	($0.002139)	$0.000000	$0.002139	100.00%
Large Power Service Mining (≥69kV)				
Basic Service Charge	$1,200.00	$1,500.00	$300.00	25.00%
Demand Charge, per kW	$17.00	$12.48	-$4.52	-26.59%
Energy Charge (kWhs)	$0.000462	$0.000500	$0.000038	8.23%
Base Power Supply Charge, all kWhs	$0.041880	$0.049332	$0.007452	17.79%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%

	Present Rate	Proposed Rate	Increase $	Increase %
Interruptible Power Service				
Basic Service Charge	$18.00	$75.00	$57.00	316.67%
Demand Charge, per kW	$5.00	$5.52	$0.52	10.40%
Energy Charge (kWhs)	$0.019408	$0.014990	-$0.004418	-22.76%
Base Power Supply Charge, all kWhs	$0.043760	$0.053090	$0.009330	21.32%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Lighting Dusk to Dawn				
New 30' Wood Pole (Class 6) - Overhead	$4.34	$4.34	$0.00	0.00%
New 30' Metal or Fiberglass - Overhead	$8.66	$8.66	$0.00	0.00%
Existing Wood Pole - Underground	$2.18	$2.18	$0.00	0.00%
New 30' Wood Pole (Class 6) - Underground	$6.52	$6.52	$0.00	0.00%
New 30' Metal or Fiberglass - Underground	$10.81	$10.81	$0.00	0.00%
Wattage, per Watt	$0.051681	$0.058707	$0.007026	13.59%
Lighting Base Power Supply Charge, per kWh	$0.010113	$0.014505	$0.004392	43.43%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
TOU - Medium General Service Schools (Formally TOU - Small General Service Schools)				
Basic Service Charge	$16.50	$100.00	$83.50	506.06%
Demand Charge, per kW	N/A	$13.47	N/A	N/A
Energy Charge 1st 400 kWh	$0.030176	$0.005480	-$0.024696	-81.84%
Energy Charge 401 -7,500 kWh	$0.043176	$0.005480	-$0.037696	-87.31%
Energy Charge >7,500 kWh	$0.076042	$0.005480	-$0.070562	-92.79%
Base Power Supply Charge, Summer On-Peak all kWhs	$0.137405	$0.120586	-$0.016819	-12.24%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.047405	$0.039200	-$0.008205	-17.31%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.137405	$0.106747	-$0.030658	-22.31%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.039185	$0.037390	-$0.001795	-4.58%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
TOU - Large General Service Schools				
Basic Service Charge	$52.00	$300.00	$248.00	476.92%
Demand Charge, per kW	$12.81	$12.88	$0.07	0.55%
Energy Charge (kWhs)	$0.005470	$0.005300	-$0.000170	-3.11%
Base Power Supply Charge, Summer On-Peak all kWhs	$0.120586	$0.148471	$0.027885	23.12%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.045586	$0.043300	-$0.002286	-5.01%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.120586	$0.144580	$0.023994	19.90%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.031868	$0.039627	$0.007759	24.35%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
RIDER R-5 ELECTRIC SERVICE SOLAR RIDER (BRIGHT ARIZONA COMMUNITY SOLAR™)				
Residential Electric, Rate R-01	$0.084510	$0.075090	-$0.009420	-11.15%
General Service, Rate SGS-10	$0.078241	$0.073290	-$0.004951	-6.33%
Medium General Service, R-MGS (Former LGS)	$0.076603	$0.073290	-$0.003313	-4.32%

[1] The Present Rate for the PPFAC is the Test Year average PPFAC, since the rate varies by month. The Proposed Rate is $0.00, since the PPFAC rate will be reset to zero for one month when the new base rates become effective. However, the PPFAC rate will change monthly in all subsequent months by an amount defined in the proposed PPFAC POA. The Company has proposed the PPFAC be a percentage based adjustment that will be recalculated monthly and reflected as a single percentage based adjustment applied to base fuel cost for each rate class (e.g. the percentage adjustment will be the same percentage value regardless of the rate class).

[2] For the new Medium General Service and Medium General Service Time-of-Use rates, the Present Rate column is populated with the currently existing rates for Large General Service and Large General Service Time-of-Use, respectively, since these two new Medium General Service classes will be comparable to the former Large General Service classes.

[3] The proposed Large Power Service rate classes will be restricted to customers with ≥69kV service. The Proposed Rate column for <69kV service is populated with the Proposed Rates from the corresponding Large General Service rate classes.

Exhibit CAJ-RJ-2

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

Schedule H-4

RESIDENTIAL SERVICE

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill
		0-400	401-1,000	1,000+	$10.00	$0.019300	$0.034350	$0.038499	$0.001140	$0.064510	-$0.002139	
Xsmall	111	111	0	0	$10.00	$2.14	$0.00	$0.00	$0.13	$7.16	-$0.24	$19.19
Small	330	330	0	0	$10.00	$6.37	$0.00	$0.00	$0.38	$21.29	-$0.71	$37.33
Medium	664	400	264	0	$10.00	$7.72	$9.07	$0.00	$0.76	$42.83	-$1.42	$68.96
Large	1,144	400	600	144	$10.00	$7.72	$20.61	$5.54	$1.30	$73.80	-$2.45	$116.53
Xlarge	2,162	400	600	1,162	$10.00	$7.72	$20.61	$44.74	$2.46	$139.47	-$4.63	$220.37
Mean	830	400	430	0	$10.00	$7.72	$14.75	$0.00	$0.95	$53.51	-$1.77	$85.16
Sum	983	400	583	0	$10.00	$7.72	$20.04	$0.00	$1.12	$63.43	-$2.10	$100.20
Win	669	400	269	0	$10.00	$7.72	$9.25	$0.00	$0.76	$43.18	-$1.43	$69.48
Annual												$1,018.12

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		0-400	401-1,000	1,000+	$15.00	$0.030100	$0.040100	$0.058100	$0.000000	$0.055090	0.000%			
Xsmall	111	111	0	0	$15.00	$3.34	$0.00	$0.00	$0.00	$6.12	$0.00	$24.46	$5.27	27.4%
Small	330	330	0	0	$15.00	$9.93	$0.00	$0.00	$0.00	$18.18	$0.00	$43.11	$5.78	15.5%
Medium	664	400	264	0	$15.00	$12.04	$10.59	$0.00	$0.00	$36.58	$0.00	$74.21	$5.25	7.6%
Large	1,144	400	600	144	$15.00	$12.04	$24.06	$8.37	$0.00	$63.02	$0.00	$122.49	$5.96	5.1%
Xlarge	2,162	400	600	1,162	$15.00	$12.04	$24.06	$67.51	$0.00	$119.11	$0.00	$237.72	$17.35	7.9%
Mean	830	400	430	0	$15.00	$12.04	$17.22	$0.00	$0.00	$45.70	$0.00	$89.96	$4.80	5.6%
Sum	983	400	583	0	$15.00	$12.04	$23.39	$0.00	$0.00	$54.17	$0.00	$104.60	$4.40	4.4%
Win	669	400	269	0	$15.00	$12.04	$10.80	$0.00	$0.00	$36.88	$0.00	$74.72	$5.24	7.5%
Annual												$1,075.95	$57.83	5.7%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND

WINTER

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh				
							$15.00	$0.030100	$0.040100	$0.058100	$0.000000	$0.055090	$0.000000	
Xsm	23%	0.6	100	100	0	0	$15.00	$3.01	$0.00	$0.00	$0.00	$5.51	$0.00	$23.52
Small	27%	1.5	294	294	0	0	$15.00	$8.85	$0.00	$0.00	$0.00	$16.20	$0.00	$40.05
Medium	30%	2.6	560	400	160	0	$15.00	$12.04	$6.42	$0.00	$0.00	$30.85	$0.00	$64.31
Large	32%	3.9	914	400	514	0	$15.00	$12.04	$20.61	$0.00	$0.00	$50.35	$0.00	$98.00
XLg	35%	6.5	1,653	400	600	653	$15.00	$12.04	$24.06	$37.94	$0.00	$91.06	$0.00	$180.10
AnnAvg	32%	3.6	830	400	430	0	$15.00	$12.04	$17.22	$0.00	$0.00	$45.70	$0.00	$89.96
WinAvg	31%	3.0	669	400	269	0	$15.00	$12.04	$10.80	$0.00	$0.00	$36.88	$0.00	$74.72

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak		All kW	All kWh							
						$15.00	$5.00	$0.01534	$0.000000						
Winter				0.26	0.74					$0.086300	$0.038610	0.000%			
Summer										$0.105800	$0.042830				
Xsm	23%	0.6	100	26	74	$15.00	$2.95	$1.53	$0.00	$2.24	$2.86	$0.00	$24.58	$1.06	4.51%
Small	27%	1.5	294	76	218	$15.00	$7.45	$4.51	$0.00	$6.56	$8.42	$0.00	$41.94	$1.89	4.72%
Medium	30%	2.6	560	145	415	$15.00	$12.85	$8.59	$0.00	$12.51	$16.02	$0.00	$64.97	$0.66	1.03%
Large	32%	3.9	914	237	677	$15.00	$19.50	$14.02	$0.00	$20.45	$26.14	$0.00	$95.11	-$2.89	-2.95%
XLg	35%	6.5	1,653	429	1,224	$15.00	$32.25	$25.36	$0.00	$37.02	$47.26	$0.00	$156.89	-$23.21	-12.89%
AnnAvg	32%	3.6	830	215	614	$15.00	$17.90	$12.73	$0.00	$18.55	$23.71	$0.00	$87.89	-$2.07	-2.31%
WinAvg	31%	3.0	669	174	496	$15.00	$14.95	$10.27	$0.00	$15.02	$19.15	$0.00	$74.39	-$0.33	-0.45%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND

SUMMER

	BILL IMPACTS PROPOSED TRANSITION RATES													
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill
								0-400 kWh	401-1,000 kWh	1,000+ kWh				
				0-400	401-1,000	1,000+	$15.00	$0.030100	$0.040100	$0.058100	$0.000000	$0.055090	$0.000000	
Xsm	24%	0.7	117	117	0	0	$15.00	$3.52	$0.00	$0.00	$0.00	$6.45	$0.00	$24.97
Small	28%	1.9	386	386	0	0	$15.00	$11.62	$0.00	$0.00	$0.00	$21.26	$0.00	$47.88
Medium	32%	3.5	813	400	413	0	$15.00	$12.04	$16.56	$0.00	$0.00	$44.79	$0.00	$88.39
Large	34%	5.6	1,395	400	600	395	$15.00	$12.04	$24.06	$22.95	$0.00	$76.85	$0.00	$150.90
XLg	37%	9.1	2,471	400	600	1,471	$15.00	$12.04	$24.06	$85.47	$0.00	$136.13	$0.00	$272.70
AnnAvg	32%	3.6	830	400	430	0	$15.00	$12.04	$17.22	$0.00	$0.00	$45.70	$0.00	$89.96
SumAvg	33%	4.1	983	400	583	0	$15.00	$12.04	$23.39	$0.00	$0.00	$54.17	$0.00	$104.60
														$1,075.95

	BILL IMPACTS PROPOSED RATES															
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak			All kW	All kWh							
							$15.00	$5.00	$0.01534	$0.000000						
Winter											$0.086300	$0.038610				
Summer				0.24	0.76						$0.105800	$0.042830	0.000%			
Xsm	24%	0.7	117	28	89		$15.00	$3.40	$1.79	$0.00	$2.96	$3.81	$0.00	$26.96	$1.99	7.96%
Small	28%	1.9	386	93	293		$15.00	$9.35	$5.92	$0.00	$9.84	$12.55	$0.00	$52.66	$4.78	9.99%
Medium	32%	3.5	813	196	617		$15.00	$17.60	$12.47	$0.00	$20.74	$26.43	$0.00	$92.24	$3.85	4.35%
Large	34%	5.6	1,395	336	1,059		$15.00	$27.95	$21.40	$0.00	$35.55	$45.36	$0.00	$145.26	-$5.64	-3.74%
XLg	37%	9.1	2,471	595	1,876		$15.00	$45.35	$37.91	$0.00	$62.95	$80.35	$0.00	$241.56	-$31.14	-11.42%
AnnAvg	32%	3.6	830	200	630		$15.00	$17.90	$12.73	$0.00	$21.16	$26.98	$0.00	$93.77	$3.81	4.23%
SumAvg	33%	4.1	983	237	747		$15.00	$20.70	$15.08	$0.00	$25.07	$31.99	$0.00	$107.84	$3.24	3.10%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND

WINTER

	BILL IMPACTS CURRENT RATES													
								Delivery						
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	0-400 kWh	401-1,000 kWh	1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill
				0-400	401-1,000	1,000+	$10.00	$0.019300	$0.034350	$0.038499	$0.001140	$0.064510	-$0.002139	
Xsm	23%	0.6	100	100	0	0	$10.00	$1.93	$0.00	$0.00	$0.11	$6.45	-$0.21	$18.28
Small	27%	1.5	294	294	0	0	$10.00	$5.67	$0.00	$0.00	$0.34	$18.97	-$0.63	$34.36
Medium	30%	2.6	560	400	160	0	$10.00	$7.72	$5.50	$0.00	$0.64	$36.13	-$1.20	$58.79
Large	32%	3.9	914	400	514	0	$10.00	$7.72	$17.66	$0.00	$1.04	$58.96	-$1.96	$93.42
XLg	35%	6.5	1,653	400	600	653	$10.00	$7.72	$20.61	$25.14	$1.88	$106.64	-$3.54	$168.45
AnnAvg	32%	3.6	830	400	430	0	$10.00	$7.72	$14.75	$0.00	$0.95	$53.51	-$1.77	$85.16
WinAvg	31%	3.0	669	400	269	0	$10.00	$7.72	$9.25	$0.00	$0.76	$43.18	-$1.43	$69.48

	BILL IMPACTS PROPOSED RATES															
								Delivery								
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	All kW	All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak		15.00	$5.00	$0.01534	$0.000000						
Winter				0.26	0.74						$0.086300	$0.038610	0.000%			
Summer											$0.105800	$0.042830				
Xsm	23%	0.6	100	26	74		$15.00	$2.95	$1.53	$0.00	$2.24	$2.86	$0.00	$24.58	$6.30	34.49%
Small	27%	1.5	294	76	218		$15.00	$7.45	$4.51	$0.00	$6.56	$8.42	$0.00	$41.94	$7.58	22.08%
Medium	30%	2.6	560	145	415		$15.00	$12.85	$8.59	$0.00	$12.51	$16.02	$0.00	$64.97	$6.18	10.52%
Large	32%	3.9	914	237	677		$15.00	$19.50	$14.02	$0.00	$20.45	$26.14	$0.00	$95.11	$1.69	1.81%
XLg	35%	6.5	1,653	429	1,224		$15.00	$32.25	$25.36	$0.00	$37.02	$47.26	$0.00	$156.89	-$11.56	-6.86%
AnnAvg	32%	3.6	830	215	614		$15.00	$17.90	$12.73	$0.00	$18.55	$23.71	$0.00	$87.89	$2.73	3.21%
WinAvg	31%	3.0	669	174	496		$15.00	$14.95	$10.27	$0.00	$15.02	$19.15	$0.00	$74.39	$4.91	7.06%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND

SUMMER

	BILL IMPACTS CURRENT RATES													
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill
								0-400 kWh	401-1,000 kWh	1,000+ kWh				
				0-400	401-1,000	1,000+	$10.00	$0.019300	$0.034350	$0.038499	$0.001140	$0.064510	-$0.002139	
Xsm	24%	0.7	117	117	0	0	$10.00	$2.26	$0.00	$0.00	$0.13	$7.55	-$0.25	$19.69
Small	28%	1.9	386	386	0	0	$10.00	$7.45	$0.00	$0.00	$0.44	$24.90	-$0.83	$41.96
Medium	32%	3.5	813	400	413	0	$10.00	$7.72	$14.19	$0.00	$0.93	$52.45	-$1.74	$83.55
Large	34%	5.6	1,395	400	600	395	$10.00	$7.72	$20.61	$15.21	$1.59	$89.99	-$2.98	$142.13
XLg	37%	9.1	2,471	400	600	1,471	$10.00	$7.72	$20.61	$56.63	$2.82	$159.40	-$5.29	$251.90
AnnAvg	32%	3.6	830	400	430	0	$10.00	$7.72	$14.75	$0.00	$0.95	$53.51	-$1.77	$85.16
SumAvg	33%	4.1	983	400	583	0	$10.00	$7.72	$20.04	$0.00	$1.12	$63.43	-$2.10	$100.20

	BILL IMPACTS PROPOSED RATES															
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
								All kW	All kWh							
				On-Peak	Off-Peak		$15.00	$5.00	$0.01534	$0.000000						
Winter											$0.086300	$0.038610				
Summer				0.24	0.76						$0.105800	$0.042830	0.000%			
Xsm	24%	0.7	117	28	89		$15.00	$3.40	$1.79	$0.00	$2.96	$3.81	$0.00	$26.96	$7.27	36.94%
Small	28%	1.9	386	93	293		$15.00	$9.35	$5.92	$0.00	$9.84	$12.55	$0.00	$52.66	$10.70	25.49%
Medium	32%	3.5	813	196	617		$15.00	$17.60	$12.47	$0.00	$20.74	$26.43	$0.00	$92.24	$8.69	10.40%
Large	34%	5.6	1,395	336	1,059		$15.00	$27.95	$21.40	$0.00	$35.55	$45.36	$0.00	$145.26	$3.13	2.20%
XLg	37%	9.1	2,471	595	1,876		$15.00	$45.35	$37.91	$0.00	$62.95	$80.35	$0.00	$241.56	-$10.34	-4.10%
AnnAvg	32%	3.6	830	200	630		$15.00	$17.90	$12.73	$0.00	$21.16	$26.98	$0.00	$93.77	$8.61	10.11%
SumAvg	33%	4.1	983	237	747		$15.00	$20.70	$15.08	$0.00	$25.07	$31.99	$0.00	$107.84	$7.64	7.62%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE CARES

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Bill	Discounts
		1-400	401+	$4.90	$0.018973	$0.035400	$0.001140	$0.061700	-$0.002139		
Xsmall	220	220	0	$4.90	$4.17	$0.00	$0.25	$13.57	-$0.47	$15.69	30.00%
Small	360	360	0	$4.90	$6.83	$0.00	$0.41	$22.21	-$0.77	$26.86	20.00%
Medium	607	400	207	$4.90	$7.59	$7.33	$0.69	$37.45	-$1.30	$50.99	10.00%
Large	990	400	590	$4.90	$7.59	$20.89	$1.13	$61.08	-$2.12	$84.12	10.00%
Xlarge	1,843	400	1,443	$4.90	$7.59	$51.08	$2.10	$113.71	-$3.94	$167.44	$8.00
Mean	753	400	353	$4.90	$7.59	$12.49	$0.86	$46.45	-$1.61	$63.61	10.00%
Sum	867	400	467	$4.90	$7.59	$16.53	$0.99	$53.49	-$1.85	$73.49	10.00%
Win	638	400	238	$4.90	$7.59	$8.43	$0.73	$39.37	-$1.37	$53.69	10.00%
Annual										$763.08	

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change	
		1-400	401+	$9.00	$0.028700	$0.048100	$0.000000	$0.050260	0.000%				
Xsmall	220	220	0	$9.00	$6.31	$0.00	$0.00	$11.06	$0.00	$18.46	$2.77	17.65%	30.00%
Small	360	360	0	$9.00	$10.33	$0.00	$0.00	$18.09	$0.00	$29.94	$3.08	11.45%	20.00%
Medium	607	400	207	$9.00	$11.48	$9.96	$0.00	$30.51	$0.00	$54.86	$3.87	7.58%	10.00%
Large	990	400	590	$9.00	$11.48	$28.38	$0.00	$49.76	$0.00	$88.76	$4.64	5.51%	10.00%
Xlarge	1,843	400	1,443	$9.00	$11.48	$69.41	$0.00	$92.63	$0.00	$174.52	$7.08	4.23%	$8.00
Mean	753	400	353	$9.00	$11.48	$16.98	$0.00	$37.84	$0.00	$67.77	$4.16	6.54%	10.00%
Sum	867	400	467	$9.00	$11.48	$22.46	$0.00	$43.57	$0.00	$77.86	$4.37	5.95%	10.00%
Win	638	400	238	$9.00	$11.48	$11.45	$0.00	$32.07	$0.00	$57.60	$3.91	7.28%	10.00%
Annual										$812.75	$49.67	6.51%	

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE CARES MEDICAL

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Revenue	Discounts
		1-400	401+	$4.90	$0.018973	$0.035400	$0.001140	$0.061700	-$0.002139		
Xsmall	365	365	0	$4.90	$6.93	$0.00	$0.42	$22.52	-$0.78	$23.79	30.00%
Small	564	400	164	$4.90	$7.59	$5.81	$0.64	$34.80	-$1.21	$36.77	30.00%
Medium	878	400	478	$4.90	$7.59	$16.92	$1.00	$54.17	-$1.88	$66.16	20.00%
Large	1,340	400	940	$4.90	$7.59	$33.28	$1.53	$82.68	-$2.87	$114.40	10.00%
Xlarge	2,304	400	1,904	$4.90	$7.59	$67.40	$2.63	$142.16	-$4.93	$211.75	$8.00
Mean	1,034	400	634	$4.90	$7.59	$22.43	$1.18	$63.78	-$2.21	$78.13	20.00%
sum	1,199	400	799	$4.90	$7.59	$28.28	$1.37	$73.97	-$2.56	$90.84	20.00%
win	871	400	471	$4.90	$7.59	$16.68	$0.99	$53.75	-$1.86	$65.64	20.00%
Annual										$938.88	

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Revenue	$ Change	% Change	
		1-400	401+	$9.00	$0.028700	$0.048100	$0.000000	$0.050260	0.000%				
Xsmall	365	365	0	$9.00	$10.48	$0.00	$0.00	$18.34	$0.00	$26.47	$2.68	11.3%	30.00%
Small	564	400	164	$9.00	$11.48	$7.89	$0.00	$28.35	$0.00	$39.70	$2.93	8.0%	30.00%
Medium	878	400	478	$9.00	$11.48	$22.99	$0.00	$44.13	$0.00	$70.08	$3.92	5.9%	20.00%
Large	1,340	400	940	$9.00	$11.48	$45.21	$0.00	$67.35	$0.00	$132.94	$18.54	16.2%	10.00%
Xlarge	2,304	400	1,904	$9.00	$11.48	$91.58	$0.00	$115.80	$0.00	$219.86	$8.11	3.8%	$8.00
Mean	1,034	400	634	$9.00	$11.48	$30.48	$0.00	$51.95	$0.00	$82.33	$4.20	5.4%	20.00%
sum	1,199	400	799	$9.00	$11.48	$38.42	$0.00	$60.25	$0.00	$95.32	$4.48	4.9%	20.00%
win	871	400	471	$9.00	$11.48	$22.66	$0.00	$43.78	$0.00	$69.54	$3.90	5.9%	20.00%
Annual										$989.14	$50.26	5.4%	

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND - CARES

WINTER

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh					
							$9.00	$0.028700	$0.048100	$0.048100	$0.000000	$0.050260	$0.000000		
Xsm	26%	1.1	198	198	0	0	$9.00	$5.68	$0.00	$0.00	$0.00	$9.95	$0.00	$17.24	30.00%
Small	28%	1.6	324	324	0	0	$9.00	$9.30	$0.00	$0.00	$0.00	$16.28	$0.00	$27.66	20.00%
Medium	30%	2.4	525	400	125	0	$9.00	$11.48	$6.01	$0.00	$0.00	$26.39	$0.00	$47.59	10.00%
Large	32%	3.6	831	400	431	0	$9.00	$11.48	$20.73	$0.00	$0.00	$41.77	$0.00	$74.68	10.00%
XLg	35%	5.9	1,496	400	600	496	$9.00	$11.48	$28.86	$23.86	$0.00	$75.19	$0.00	$140.39	$8.00
AnnAvg	31%	3.3	753	400	353	0	$9.00	$11.48	$16.98	$0.00	$0.00	$37.84	$0.00	$67.77	10.00%
WinAvg	31%	2.9	638	400	238	0	$9.00	$11.48	$11.45	$0.00	$0.00	$32.07	$0.00	$57.60	10.00%

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change	
							All kW	All kWh								
				On-Peak	Off-Peak	15.00	5.00	$0.01534	$0.000000							
Winter				0.26	0.74					$0.086300	$0.038610	0.000%				
Summer										$0.105800	$0.042830					
Xsm	26%	1.1	198	51	147	$15.00	$5.50	$3.04	$0.00	$4.40	$5.68	$0.00	$16.62	-$0.62	-3.6%	$17.00
Small	28%	1.6	324	84	240	$15.00	$8.00	$4.97	$0.00	$7.25	$9.27	$0.00	$27.49	-$0.17	-0.6%	$17.00
Medium	30%	2.4	525	136	389	$15.00	$12.00	$8.05	$0.00	$11.74	$15.02	$0.00	$44.81	-$2.78	-5.8%	$17.00
Large	32%	3.6	831	216	615	$15.00	$18.00	$12.75	$0.00	$18.64	$23.75	$0.00	$71.14	-$3.54	-4.7%	$17.00
XLg	35%	5.9	1,496	388	1,108	$15.00	$29.50	$22.95	$0.00	$33.48	$42.78	$0.00	$126.71	-$13.68	-9.7%	$17.00
AnnAvg	31%	3.3	753	195	558	$15.00	$16.50	$11.55	$0.00	$16.83	$21.54	$0.00	$64.42	-$3.35	-4.9%	$17.00
WinAvg	31%	2.9	638	166	472	$15.00	$14.50	$9.79	$0.00	$14.33	$18.22	$0.00	$54.84	-$2.76	-4.8%	$17.00

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND - CARES

SUMMER

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+	$9.00	$0.028700	$0.048100	$0.048100	$0.000000	$0.050260	$0.000000		
Xsm	26%	1.3	243	243	0	0	$9.00	$6.97	$0.00	$0.00	$0.00	$12.21	$0.00	$19.73	30.00%
Small	29%	2.0	413	400	13	0	$9.00	$11.48	$0.63	$0.00	$0.00	$20.76	$0.00	$33.49	20.00%
Medium	31%	3.1	709	400	309	0	$9.00	$11.48	$14.86	$0.00	$0.00	$35.63	$0.00	$63.88	10.00%
Large	33%	4.8	1,161	400	600	161	$9.00	$11.48	$28.86	$7.74	$0.00	$58.35	$0.00	$107.43	$8.00
XLg	36%	7.8	2,078	400	600	1,078	$9.00	$11.48	$28.86	$51.85	$0.00	$104.44	$0.00	$197.63	$8.00
AnnAvg	31%	3.3	753	400	353	0	$9.00	$11.48	$16.98	$0.00	$0.00	$37.84	$0.00	$67.77	10.00%
SumAvg	32%	3.7	863	400	463	0	$9.00	$11.48	$22.29	$0.00	$0.00	$43.39	$0.00	$77.54	10.00%

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh) On-Peak	Delivery (kWh) Off-Peak	Basic Service Charge	Delivery All kW	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change	
						$15.00	$5.00	$0.01534	$0.000000							
Winter										$0.086300	$0.038610					
Summer				0.24	0.76					$0.105800	$0.042830	0.000%				
Xsm	26%	1.3	243	58	185	$15.00	$6.50	$3.73	$0.00	$6.14	$7.92	$0.00	$22.29	$2.56	13.0%	$17.00
Small	29%	2.0	413	99	314	$15.00	$10.00	$6.34	$0.00	$10.47	$13.45	$0.00	$38.26	$4.77	14.2%	$17.00
Medium	31%	3.1	709	171	538	$15.00	$15.50	$10.88	$0.00	$18.09	$23.04	$0.00	$65.51	$1.63	2.6%	$17.00
Large	33%	4.8	1,161	279	882	$15.00	$24.00	$17.81	$0.00	$29.52	$37.78	$0.00	$107.11	-$0.32	-0.3%	$17.00
XLg	36%	7.8	2,078	500	1,578	$15.00	$39.00	$31.88	$0.00	$52.90	$67.59	$0.00	$189.37	-$8.26	-4.2%	$17.00
AnnAvg	31%	3.3	753	181	572	$15.00	$16.50	$11.55	$0.00	$19.15	$24.50	$0.00	$69.70	$1.93	2.8%	$17.00
SumAvg	32%	3.7	863	208	656	$15.00	$18.50	$13.24	$0.00	$22.01	$28.10	$0.00	$79.85	$2.31	3.0%	$17.00

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND - CARES

WINTER

	BILL IMPACTS CURRENT RATES														
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh					
							$4.90	$0.018973	$0.035400	$0.035400	$0.001140	$0.061700	-$0.002139		
Xsm	26%	1.1	198	198	0	0	$4.90	$3.76	$0.00	$0.00	$0.23	$12.22	-$0.42	$14.48	30.00%
Small	28%	1.6	324	324	0	0	$4.90	$6.15	$0.00	$0.00	$0.37	$19.99	-$0.69	$24.57	20.00%
Medium	30%	2.4	525	400	125	0	$4.90	$7.59	$4.43	$0.00	$0.60	$32.39	-$1.12	$43.90	10.00%
Large	32%	3.6	831	400	431	0	$4.90	$7.59	$15.26	$0.00	$0.95	$51.27	-$1.78	$70.37	10.00%
XLg	35%	5.9	1,496	400	600	496	$4.90	$7.59	$21.24	$17.56	$1.71	$92.30	-$3.20	$134.10	$8.00
AnnAvg	31%	3.3	753	400	353	0	$4.90	$7.59	$12.49	$0.00	$0.86	$46.45	-$1.61	$63.61	10.00%
WinAvg	31%	2.9	638	400	238	0	$4.90	$7.59	$8.43	$0.00	$0.73	$39.37	-$1.37	$53.69	10.00%

	BILL IMPACTS PROPOSED RATES															
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
				On-Peak	Off-Peak		All kW	All kWh								
						15.00	5.00	$0.01534	$0.000000							
Winter				0.26	0.74					$0.086300	$0.038610	0.000%				
Summer										$0.105800	$0.042830					
Xsm	26%	1.1	198	51	147	$15.00	$5.50	$3.04	$0.00	$4.40	$5.68	$0.00	$16.62	$2.14	14.8%	$17.00
Small	28%	1.6	324	84	240	$15.00	$8.00	$4.97	$0.00	$7.25	$9.27	$0.00	$27.49	$2.92	11.9%	$17.00
Medium	30%	2.4	525	136	389	$15.00	$12.00	$8.05	$0.00	$11.74	$15.02	$0.00	$44.81	$0.91	2.1%	$17.00
Large	32%	3.6	831	216	615	$15.00	$18.00	$12.75	$0.00	$18.64	$23.75	$0.00	$71.14	$0.77	1.1%	$17.00
XLg	35%	5.9	1,496	388	1,108	$15.00	$29.50	$22.95	$0.00	$33.48	$42.78	$0.00	$126.71	-$7.39	-5.5%	$17.00
AnnAvg	31%	3.3	753	195	558	$15.00	$16.50	$11.55	$0.00	$16.83	$21.54	$0.00	$64.42	$0.81	1.3%	$17.00
WinAvg	31%	2.9	638	166	472	$15.00	$14.50	$9.79	$0.00	$14.33	$18.22	$0.00	$54.84	$1.15	2.1%	$17.00

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND - CARES

SUMMER

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh					
							$4.90	$0.018973	$0.035400	$0.035400	$0.001140	$0.061700	-$0.002139		
Xsm	26%	1.3	243	243	0	0	$4.90	$4.61	$0.00	$0.00	$0.28	$14.99	-$0.52	$16.98	30.00%
Small	29%	2.0	413	400	13	0	$4.90	$7.59	$0.46	$0.00	$0.47	$25.48	-$0.88	$30.41	20.00%
Medium	31%	3.1	709	400	309	0	$4.90	$7.59	$10.94	$0.00	$0.81	$43.75	-$1.52	$59.82	10.00%
Large	33%	4.8	1,161	400	600	161	$4.90	$7.59	$21.24	$5.70	$1.32	$71.63	-$2.48	$101.89	$8.00
XLg	36%	7.8	2,078	400	600	1,078	$4.90	$7.59	$21.24	$38.16	$2.37	$128.21	-$4.45	$190.02	$8.00
AnnAvg	31%	3.3	753	400	353	0	$4.90	$7.59	$12.49	$0.00	$0.86	$46.45	-$1.61	$63.61	10.00%
SumAvg	32%	3.7	863	400	463	0	$4.90	$7.59	$16.40	$0.00	$0.98	$53.27	-$1.85	$73.17	10.00%

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
				On-Peak	Off-Peak			All kW	All kWh								
							$15.00	$5.00	$0.01534	$0.000000							
Winter											$0.086300	$0.038610					
Summer				0.24	0.76						$0.105800	$0.042830	0.000%				
Xsm	26%	1.3	243	58	185		$15.00	$6.50	$3.73	$0.00	$6.14	$7.92	$0.00	$22.29	$5.31	31.3%	$17.00
Small	29%	2.0	413	99	314		$15.00	$10.00	$6.34	$0.00	$10.47	$13.45	$0.00	$38.26	$7.85	25.8%	$17.00
Medium	31%	3.1	709	171	538		$15.00	$15.50	$10.88	$0.00	$18.09	$23.04	$0.00	$65.51	$5.69	9.5%	$17.00
Large	33%	4.8	1,161	279	882		$15.00	$24.00	$17.81	$0.00	$29.52	$37.78	$0.00	$107.11	$5.22	5.1%	$17.00
XLg	36%	7.8	2,078	500	1,578		$15.00	$39.00	$31.88	$0.00	$52.90	$67.59	$0.00	$189.37	-$0.65	-0.3%	$17.00
AnnAvg	31%	3.3	753	181	572		$15.00	$16.50	$11.55	$0.00	$19.15	$24.50	$0.00	$69.70	$6.09	9.6%	$17.00
SumAvg	32%	3.7	863	208	656		$15.00	$18.50	$13.24	$0.00	$22.01	$28.10	$0.00	$79.85	$6.68	9.1%	$17.00

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND - CARES MEDICAL

WINTER

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh					
							$9.00	$0.028700	$0.048100	$0.048100	$0.000000	$0.050260	$0.000000		
Xsm	28%	1.6	323	323	0	0	$9.00	$9.27	$0.00	$0.00	$0.00	$16.23	$0.00	$24.15	30.00%
Small	29%	2.3	495	400	95	0	$9.00	$11.48	$4.57	$0.00	$0.00	$24.88	$0.00	$34.95	30.00%
Medium	31%	3.3	763	400	363	0	$9.00	$11.48	$17.46	$0.00	$0.00	$38.35	$0.00	$61.03	20.00%
Large	33%	4.6	1,115	400	600	115	$9.00	$11.48	$28.86	$5.53	$0.00	$56.04	$0.00	$88.73	20.00%
XLg	36%	7.2	1,887	400	600	887	$9.00	$11.48	$28.86	$42.66	$0.00	$94.84	$0.00	$168.16	10.00%
AnnAvg	33%	4.3	1,034	400	600	34	$9.00	$11.48	$28.86	$1.62	$0.00	$51.95	$0.00	$82.33	20.00%
WinAvg	32%	3.7	871	400	471	0	$9.00	$11.48	$22.66	$0.00	$0.00	$43.78	$0.00	$69.54	20.00%

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
				On-Peak	Off-Peak		All kW	All kWh								
						15.00	5.00	$0.01534	$0.000000							
Winter				0.26	0.74					$0.086300	$0.038610	0.000%				
Summer										$0.105800	$0.042830					
Xsm	28%	1.6	323	84	239	$15.00	$8.00	$4.95	$0.00	$7.25	$9.23	$0.00	$17.43	-$6.72	-27.8%	$27.00
Small	29%	2.3	495	128	367	$15.00	$11.50	$7.59	$0.00	$11.05	$14.17	$0.00	$32.31	-$2.64	-7.6%	$27.00
Medium	31%	3.3	763	198	565	$15.00	$16.50	$11.70	$0.00	$17.09	$21.81	$0.00	$55.10	-$5.93	-9.7%	$27.00
Large	33%	4.6	1,115	289	826	$15.00	$23.00	$17.10	$0.00	$24.94	$31.89	$0.00	$84.93	-$3.80	-4.3%	$27.00
XLg	36%	7.2	1,887	490	1,397	$15.00	$36.00	$28.95	$0.00	$42.29	$53.94	$0.00	$149.18	-$18.98	-11.3%	$27.00
AnnAvg	33%	4.3	1,034	268	765	$15.00	$21.50	$15.86	$0.00	$23.13	$29.54	$0.00	$78.03	-$4.30	-5.2%	$27.00
WinAvg	32%	3.7	871	226	645	$15.00	$18.50	$13.36	$0.00	$19.50	$24.90	$0.00	$64.26	-$5.28	-7.6%	$27.00

Notes: 1. This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND - CARES MEDICAL

SUMMER

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh					
							$9.00	$0.028700	$0.048100	$0.048100	$0.000000	$0.050260	$0.000000		
Xsm	29%	2.0	414	400	14	0	$9.00	$11.48	$0.67	$0.00	$0.00	$20.81	$0.00	$29.37	30.00%
Small	31%	3.0	663	400	263	0	$9.00	$11.48	$12.63	$0.00	$0.00	$33.30	$0.00	$53.13	20.00%
Medium	33%	4.3	1,035	400	600	35	$9.00	$11.48	$28.86	$1.68	$0.00	$52.02	$0.00	$82.43	20.00%
Large	35%	6.2	1,572	400	600	572	$9.00	$11.48	$28.86	$27.49	$0.00	$78.98	$0.00	$140.23	10.00%
XLg	38%	9.5	2,601	400	600	1,601	$9.00	$11.48	$28.86	$77.01	$0.00	$130.73	$0.00	$249.08	$8.00
AnnAvg	33%	4.3	1,034	400	600	34	$9.00	$11.48	$28.86	$1.62	$0.00	$51.95	$0.00	$82.33	20.00%
SumAvg	33%	4.9	1,194	400	600	194	$9.00	$11.48	$28.86	$9.32	$0.00	$60.00	$0.00	$94.93	20.00%

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
				On-Peak	Off-Peak		All kW	All kWh								
						$15.00	$5.00	$0.01534	$0.000000							
Winter										$0.086300	$0.038610					
Summer				0.24	0.76					$0.105800	$0.042830	0.000%				
Xsm	29%	2.0	414	100	314	$15.00	$10.00	$6.35	$0.00	$10.58	$13.45	$0.00	$28.38	-$0.99	-3.4%	$27.00
Small	31%	3.0	663	159	503	$15.00	$15.00	$10.16	$0.00	$16.82	$21.54	$0.00	$51.52	-$1.61	-3.0%	$27.00
Medium	33%	4.3	1,035	249	786	$15.00	$21.50	$15.88	$0.00	$26.34	$33.66	$0.00	$85.38	$2.95	3.6%	$27.00
Large	35%	6.2	1,572	378	1,193	$15.00	$31.00	$24.11	$0.00	$39.99	$51.10	$0.00	$134.20	-$6.03	-4.3%	$27.00
XLg	38%	9.5	2,601	626	1,975	$15.00	$47.50	$39.90	$0.00	$66.23	$84.59	$0.00	$226.22	-$22.86	-9.2%	$27.00
AnnAvg	33%	4.3	1,034	249	785	$15.00	$21.50	$15.86	$0.00	$26.34	$33.62	$0.00	$85.32	$2.99	3.6%	$27.00
SumAvg	33%	4.9	1,194	287	907	$15.00	$24.50	$18.31	$0.00	$30.36	$38.85	$0.00	$100.02	$5.09	5.4%	$27.00

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

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UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND - CARES MEDICAL

WINTER

	BILL IMPACTS CURRENT RATES														
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh					
							$4.90	$0.018973	$0.035400	$0.035400	$0.001140	$0.061700	-$0.002139		
Xsm	28%	1.6	323	323	0	0	$4.90	$6.13	$0.00	$0.00	$0.37	$19.93	-$0.69	$21.45	30.00%
Small	29%	2.3	495	400	95	0	$4.90	$7.59	$3.36	$0.00	$0.56	$30.54	-$1.06	$32.13	30.00%
Medium	31%	3.3	763	400	363	0	$4.90	$7.59	$12.85	$0.00	$0.87	$47.08	-$1.63	$57.33	20.00%
Large	33%	4.6	1,115	400	600	115	$4.90	$7.59	$21.24	$4.07	$1.27	$68.80	-$2.39	$84.39	20.00%
XLg	36%	7.2	1,887	400	600	887	$4.90	$7.59	$21.24	$31.40	$2.15	$116.43	-$4.04	$161.70	10.00%
AnnAvg	33%	4.3	1,034	400	600	34	$4.90	$7.59	$21.24	$1.19	$1.18	$63.78	-$2.21	$78.14	20.00%
WinAvg	32%	3.7	871	400	471	0	$4.90	$7.59	$16.68	$0.00	$0.99	$53.75	-$1.86	$65.63	20.00%

	BILL IMPACTS PROPOSED RATES																
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
				On-Peak	Off-Peak		15.00	All kW	All kWh								
								5.00	$0.01534	$0.000000							
Winter				0.26	0.74						$0.086300	$0.038610	0.000%				
Summer											$0.105800	$0.042830					
Xsm	28%	1.6	323	84	239		$15.00	$8.00	$4.95	$0.00	$7.25	$9.23	$0.00	$17.43	-$4.02	-18.7%	$27.00
Small	29%	2.3	495	128	367		$15.00	$11.50	$7.59	$0.00	$11.05	$14.17	$0.00	$32.31	$0.18	0.6%	$27.00
Medium	31%	3.3	763	198	565		$15.00	$16.50	$11.70	$0.00	$17.09	$21.81	$0.00	$55.10	-$2.23	-3.9%	$27.00
Large	33%	4.6	1,115	289	826		$15.00	$23.00	$17.10	$0.00	$24.94	$31.89	$0.00	$84.93	$0.54	0.6%	$27.00
XLg	36%	7.2	1,887	490	1,397		$15.00	$36.00	$28.95	$0.00	$42.29	$53.94	$0.00	$149.18	-$12.52	-7.7%	$27.00
AnnAvg	33%	4.3	1,034	268	765		$15.00	$21.50	$15.86	$0.00	$23.13	$29.54	$0.00	$78.03	-$0.11	-0.1%	$27.00
WinAvg	32%	3.7	871	226	645		$15.00	$18.50	$13.36	$0.00	$19.50	$24.90	$0.00	$64.26	-$1.37	-2.1%	$27.00

Notes: 1. This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

Exhibit CAJ-RJ-2

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

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RESIDENTIAL SERVICE DEMAND - CARES MEDICAL

SUMMER

	BILL IMPACTS CURRENT RATES														
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh					
							$4.90	$0.018973	$0.035400	$0.035400	$0.001140	$0.061700	-$0.002139		
Xsm	29%	2.0	414	400	14	0	$4.90	$7.59	$0.50	$0.00	$0.47	$25.54	-$0.89	$26.68	30.00%
Small	31%	3.0	663	400	263	0	$4.90	$7.59	$9.29	$0.00	$0.76	$40.88	-$1.42	$49.60	20.00%
Medium	33%	4.3	1,035	400	600	35	$4.90	$7.59	$21.24	$1.24	$1.18	$63.86	-$2.21	$78.24	20.00%
Large	35%	6.2	1,572	400	600	572	$4.90	$7.59	$21.24	$20.23	$1.79	$96.96	-$3.36	$134.41	10.00%
XLg	38%	9.5	2,601	400	600	1,601	$4.90	$7.59	$21.24	$56.68	$2.97	$160.48	-$5.56	$240.29	$8.00
AnnAvg	33%	4.3	1,034	400	600	34	$4.90	$7.59	$21.24	$1.19	$1.18	$63.78	-$2.21	$78.14	20.00%
SumAvg	33%	4.9	1,194	400	600	194	$4.90	$7.59	$21.24	$6.86	$1.36	$73.66	-$2.55	$90.44	20.00%

	BILL IMPACTS PROPOSED RATES															
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
				On-Peak	Off-Peak		All kW	All kWh								
						$15.00	$5.00	$0.01534	$0.000000							
Winter										$0.086300	$0.038610					
Summer				0.24	0.76					$0.105800	$0.042830	0.000%				
Xsm	29%	2.0	414	100	314	$15.00	$10.00	$6.35	$0.00	$10.58	$13.45	$0.00	$28.38	$1.70	6.4%	$27.00
Small	31%	3.0	663	159	503	$15.00	$15.00	$10.16	$0.00	$16.82	$21.54	$0.00	$51.52	$1.92	3.9%	$27.00
Medium	33%	4.3	1,035	249	786	$15.00	$21.50	$15.88	$0.00	$26.34	$33.66	$0.00	$85.38	$7.14	9.1%	$27.00
Large	35%	6.2	1,572	378	1,193	$15.00	$31.00	$24.11	$0.00	$39.99	$51.10	$0.00	$134.20	-$0.21	-0.2%	$27.00
XLg	38%	9.5	2,601	626	1,975	$15.00	$47.50	$39.90	$0.00	$66.23	$84.59	$0.00	$226.22	-$14.07	-5.9%	$27.00
AnnAvg	33%	4.3	1,034	249	785	$15.00	$21.50	$15.86	$0.00	$26.34	$33.62	$0.00	$85.32	$7.18	9.2%	$27.00
SumAvg	33%	4.9	1,194	287	907	$15.00	$24.50	$18.31	$0.00	$30.36	$38.85	$0.00	$100.02	$9.58	10.6%	$27.00

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+							
	Winter	0.24	0.76				$11.50	$0.030350	$0.001140	$0.129605	$0.031385	-$0.002139	
	Summer									$0.129605	$0.039605		
Xsm	150	36	114	150	0	0	$11.50	$4.55	$0.17	$4.67	$3.58	-$0.32	$24.15
Small	286	69	217	286	0	0	$11.50	$8.68	$0.33	$8.90	$6.82	-$0.61	$35.62
Medium	641	154	487	400	241	0	$11.50	$19.45	$0.73	$19.94	$15.29	-$1.37	$65.54
Large	1,043	250	793	400	600	43	$11.50	$31.66	$1.19	$32.44	$24.88	-$2.23	$99.44
XLg	1,810	434	1,376	400	600	810	$11.50	$54.93	$2.06	$56.30	$43.17	-$3.87	$164.09
AnnAvg	1,008	242	766	400	600	8	$11.50	$30.59	$1.15	$31.36	$24.05	-$2.16	$96.49
Avg Win	801	192	608	400	401	0	$11.50	$24.30	$0.91	$24.90	$19.10	-$1.71	$79.00

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+							
	Winter						$15.00	$0.035300	$0.035300	$0.035300	$0.000000	$0.091550	$0.038610	0.000%			
	Summer											$0.111001	$0.042830			$ Change	% Change
Xsm	150	36	114	150	0	0	$15.00	$5.30	$0.00	$0.00	$0.00	$3.30	$4.40	$0.00	$28.00	$3.85	15.94%
Small	286	69	217	286	0	0	$15.00	$10.10	$0.00	$0.00	$0.00	$6.28	$8.39	$0.00	$39.77	$4.15	11.65%
Medium	641	154	487	400	241	0	$15.00	$14.12	$8.51	$0.00	$0.00	$14.08	$18.81	$0.00	$70.52	$4.98	7.60%
Large	1,043	250	793	400	600	43	$15.00	$14.12	$21.18	$1.52	$0.00	$22.92	$30.61	$0.00	$105.35	$5.91	5.94%
XLg	1,810	434	1,376	400	600	810	$15.00	$14.12	$21.18	$28.59	$0.00	$39.77	$53.11	$0.00	$171.77	$7.68	4.68%
AnnAvg	1,008	242	766	400	600	8	$15.00	$14.12	$21.18	$0.28	$0.00	$22.15	$29.58	$0.00	$102.31	$5.82	6.03%
Avg Win	801	192	608	400	401	0	$15.00	$14.12	$14.14	$0.00	$0.00	$17.59	$23.49	$0.00	$84.34	$5.34	6.76%

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+							
	Winter						$11.50	$0.030350	$0.001140	$0.129605	$0.031385	-$0.002139	
	Summer	0.23	0.77							$0.129605	$0.039605		
Xsm	261	60	201	261	0	0	$11.50	$7.92	$0.30	$7.78	$7.96	-$0.56	$34.90
Small	525	121	404	400	125	0	$11.50	$15.93	$0.60	$15.65	$16.01	-$1.12	$58.57
Medium	983	226	757	400	583	0	$11.50	$29.83	$1.12	$29.30	$29.98	-$2.10	$99.63
Large	1,611	371	1,240	400	600	611	$11.50	$48.89	$1.84	$48.02	$49.13	-$3.45	$155.93
XLg	2,681	617	2,064	400	600	1,681	$11.50	$81.37	$3.06	$79.92	$81.76	-$5.74	$251.87
AnnAvg	1,008	232	776	400	600	8	$11.50	$30.59	$1.15	$30.05	$30.74	-$2.16	$101.87
Avg Sum	1,195	275	920	400	600	195	$11.50	$36.26	$1.36	$35.61	$36.43	-$2.56	$118.60

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+							
	Winter						$15.00	$0.035300	$0.035300	$0.035300	$0.000000	$0.091550	$0.038610				
	Summer											$0.111001	$0.042830	0.000%		$ Change	% Change
Xsm	261	60	201	261	0	0	$15.00	$9.21	$0.00	$0.00	$0.00	$6.66	$8.61	$0.00	$39.48	$4.58	13.12%
Small	525	121	404	400	125	0	$15.00	$14.12	$4.41	$0.00	$0.00	$13.40	$17.31	$0.00	$64.24	$5.67	9.69%
Medium	983	226	757	400	583	0	$15.00	$14.12	$20.58	$0.00	$0.00	$25.10	$32.42	$0.00	$107.22	$7.59	7.62%
Large	1,611	371	1,240	400	600	611	$15.00	$14.12	$21.18	$21.57	$0.00	$41.13	$53.13	$0.00	$166.13	$10.20	6.54%
XLg	2,681	617	2,064	400	600	1,681	$15.00	$14.12	$21.18	$59.34	$0.00	$68.45	$88.42	$0.00	$266.51	$14.64	5.81%
AnnAvg	1,008	232	776	400	600	8	$15.00	$14.12	$21.18	$0.28	$0.00	$25.74	$33.25	$0.00	$109.57	$7.70	7.56%
Avg Sum	1,195	275	920	400	600	195	$15.00	$14.12	$21.18	$6.87	$0.00	$30.50	$39.40	$0.00	$127.07	$8.47	7.14%

	Net Bill	$ Change	% Change
Current Annual	$1,185.62		
Proposed Annual	$1,268.46	$82.84	6.99%

Exhibit CAJ-RJ-2

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

Schedule H-4

RESIDENTIAL SERVICE RATE TIME OF USE DEMAND

WINTER

BILL IMPACTS PROPOSED RES-TOU RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
	Winter	0.24	0.76				$15.00	$0.035300	$0.035300	$0.035300	$0.000000	$0.091550	$0.038610	0.000%	
	Summer											$0.111001	$0.042830		
Xsm	150	36	114	150	0	0	$15.00	$5.30	$0.00	$0.00	$0.00	$3.30	$4.40	$0.00	$28.00
Small	286	69	217	286	0	0	$15.00	$10.10	$0.00	$0.00	$0.00	$6.28	$8.39	$0.00	$39.77
Medium	641	154	487	400	241	0	$15.00	$14.12	$8.51	$0.00	$0.00	$14.08	$18.81	$0.00	$70.52
Large	1,043	250	793	400	600	43	$15.00	$14.12	$21.18	$1.52	$0.00	$22.92	$30.61	$0.00	$105.35
XLg	1,810	434	1,376	400	600	810	$15.00	$14.12	$21.18	$28.59	$0.00	$39.77	$53.11	$0.00	$171.77
AnnAvg	1,008	242	766	400	600	8	$15.00	$14.12	$21.18	$0.28	$0.00	$22.15	$29.58	$0.00	$102.31
WinAvg	801	192	608	400	401	0	$15.00	$14.12	$14.14	$0.00	$0.00	$17.59	$23.49	$0.00	$84.34

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
								All kW	All kWh							
		On-Peak	Off-Peak				$15.00	$5.00	$0.01534	$0.000000						
Winter		0.24	0.76								$0.086300	$0.038610	0.000%			
Summer											$0.105800	$0.042830				
Xsm	150	36	114	25%	0.8		$15.00	$4.00	$2.30	$0.00	$3.11	$4.40	$0.00	$28.81	$0.81	2.89%
Small	286	69	217	27%	1.4		$15.00	$7.00	$4.39	$0.00	$5.92	$8.39	$0.00	$40.70	$0.93	2.34%
Medium	641	154	487	30%	2.9		$15.00	$14.50	$9.83	$0.00	$13.28	$18.81	$0.00	$71.42	$0.90	1.28%
Large	1,043	250	793	33%	4.4		$15.00	$22.00	$16.00	$0.00	$21.60	$30.61	$0.00	$105.21	-$0.14	-0.13%
XLg	1,810	434	1,376	36%	7.0		$15.00	$35.00	$27.77	$0.00	$37.49	$53.11	$0.00	$168.37	-$3.40	-1.98%
AnnAvg	1,008	242	766	33%	4.2		$15.00	$21.00	$15.46	$0.00	$20.88	$29.58	$0.00	$101.92	-$0.39	-0.38%
WinAvg	801	192	608	32%	3.5		$15.00	$17.50	$12.28	$0.00	$16.58	$23.49	$0.00	$84.85	$0.51	0.60%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE DEMAND

SUMMER

BILL IMPACTS PROPOSED RES-TOU RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
	Winter						$15.00	$0.035300	$0.035300	$0.035300	$0.000000	$0.091550	$0.038610		
	Summer	0.23	0.77									$0.111001	$0.042830	0.000%	
Xsm	261	60	201	261	0	0	$15.00	$9.21	$0.00	$0.00	$0.00	$6.66	$8.61	$0.00	$39.48
Small	525	121	404	400	125	0	$15.00	$14.12	$4.41	$0.00	$0.00	$13.40	$17.31	$0.00	$64.24
Medium	983	226	757	400	583	0	$15.00	$14.12	$20.58	$0.00	$0.00	$25.10	$32.42	$0.00	$107.22
Large	1,611	371	1,240	400	600	611	$15.00	$14.12	$21.18	$21.57	$0.00	$41.13	$53.13	$0.00	$166.13
XLg	2,681	617	2,064	400	600	1,681	$15.00	$14.12	$21.18	$59.34	$0.00	$68.45	$88.42	$0.00	$266.51
AnnAvg	1,008	232	776	400	600	8	$15.00	$14.12	$21.18	$0.28	$0.00	$25.74	$33.25	$0.00	$109.57
SumAvg	1,195	275	920	400	600	195	$15.00	$14.12	$21.18	$6.87	$0.00	$30.50	$39.40	$0.00	$127.07

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)	Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak				All kW	All kWh							
						$15.00	$5.00	$0.01534	$0.000000						
Winter										$0.086300	$0.038610				
Summer		0.23	0.77							$0.105800	$0.042830	0.000%			
Xsm	261	60	201	27%	1.3	$15.00	$6.50	$4.00	$0.00	$6.35	$8.61	$0.00	$40.46	$0.98	2.48%
Small	525	121	404	30%	2.4	$15.00	$12.00	$8.05	$0.00	$12.80	$17.30	$0.00	$65.15	$0.91	1.42%
Medium	983	226	757	32%	4.1	$15.00	$20.50	$15.08	$0.00	$23.91	$32.42	$0.00	$106.91	-$0.31	-0.29%
Large	1,611	371	1,240	35%	6.3	$15.00	$31.50	$24.71	$0.00	$39.25	$53.11	$0.00	$163.57	-$2.56	-1.54%
XLg	2,681	617	2,064	38%	9.7	$15.00	$48.50	$41.13	$0.00	$65.28	$88.40	$0.00	$258.31	-$8.20	-3.08%
AnnAvg	1,008	232	776	33%	4.2	$15.00	$21.00	$15.46	$0.00	$24.55	$33.24	$0.00	$109.25	-$0.32	-0.29%
SumAvg	1,195	275	920	33%	4.9	$15.00	$24.50	$18.33	$0.00	$29.10	$39.40	$0.00	$126.33	-$0.74	-0.58%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE DEMAND

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+							
	Winter	0.24	0.76				$11.50	$0.030350	$0.001140	$0.129605	$0.031385	-$0.002139	
	Summer									$0.129605	$0.039605		
Xsm	150	36	114	150	0	0	$11.50	$4.55	$0.17	$4.67	$3.58	($0.32)	$24.15
Small	286	69	217	286	0	0	$11.50	$8.68	$0.33	$8.90	$6.82	($0.61)	$35.62
Medium	641	154	487	400	241	0	$11.50	$19.45	$0.73	$19.94	$15.29	($1.37)	$65.54
Large	1,043	250	793	400	600	43	$11.50	$31.66	$1.19	$32.44	$24.88	($2.23)	$99.44
XLg	1,810	434	1,376	400	600	810	$11.50	$54.93	$2.06	$56.30	$43.17	($3.87)	$164.09
AnnAvg	1,008	242	766	400	600	8	$11.50	$30.59	$1.15	$31.36	$24.05	($2.16)	$96.49
WinAvg	801	192	608	400	401	0	$11.50	$24.30	$0.91	$24.90	$19.10	($1.71)	$79.00

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)		Basic Service Charge	Delivery All kW	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak				$15.00	$5.00	$0.01534	$0.000000						
Winter		0.24	0.76								$0.086300	$0.038610	0.000%			
Summer											$0.105800	$0.042830				
Xsm	150	36	114	25%	0.8		$15.00	$4.20	$2.30	$0.00	$3.11	$4.40	$0.00	$29.01	$4.86	20.12%
Small	286	69	217	27%	1.5		$15.00	$7.25	$4.39	$0.00	$5.92	$8.39	$0.00	$40.95	$5.33	14.96%
Medium	641	154	487	30%	2.9		$15.00	$14.40	$9.83	$0.00	$13.28	$18.81	$0.00	$71.32	$5.78	8.82%
Large	1,043	250	793	33%	4.4		$15.00	$21.80	$16.00	$0.00	$21.60	$30.61	$0.00	$105.01	$5.57	5.60%
XLg	1,810	434	1,376	36%	7.0		$15.00	$34.85	$27.77	$0.00	$37.49	$53.11	$0.00	$168.22	$4.13	2.52%
AnnAvg	1,008	242	766	33%	4.2		$15.00	$21.20	$15.46	$0.00	$20.88	$29.58	$0.00	$102.12	$5.63	5.83%
WinAvg	801	192	608	32%	3.5		$15.00	$17.40	$12.28	$0.00	$16.58	$23.49	$0.00	$84.75	$5.75	7.28%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

Exhibit CAJ-RJ-2

UNS Electric, Inc.

Schedule H-4

Typical Bill Comparison - Present and Proposed Rates

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Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE DEMAND

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+							
	Winter	0.24	0.76				$11.50	$0.030350	$0.001140	$0.129605	$0.031385		
	Summer									$0.129605	$0.039605	-$0.002139	
Xsm	261	63	198	261	0	0	$11.50	$7.92	$0.30	$8.12	$7.86	($0.56)	$35.14
Small	525	126	399	400	125	0	$11.50	$15.93	$0.60	$16.33	$15.80	($1.12)	$59.04
Medium	983	236	747	400	583	0	$11.50	$29.83	$1.12	$30.58	$29.59	($2.10)	$100.52
Large	1,611	387	1,224	400	600	611	$11.50	$48.89	$1.84	$50.11	$48.49	($3.45)	$157.38
XLg	2,681	643	2,038	400	600	1,681	$11.50	$81.37	$3.06	$83.39	$80.70	($5.74)	$254.28
AnnAvg	1,008	242	766	400	600	8	$11.50	$30.59	$1.15	$31.36	$30.34	($2.16)	$102.78
WinAvg	1,195	287	908	400	600	195	$11.50	$36.26	$1.36	$37.16	$35.96	($2.56)	$119.68

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
								All kW	All kWh							
		On-Peak	Off-Peak				$15.00	$5.00	$0.01534	$0.000000						
Winter											$0.086300	$0.038610				
Summer		0.23	0.77								$0.105800	$0.042830	0.000%			
Xsm	261	60	201	27%	1.3		$15.00	$6.70	$4.00	$0.00	$6.35	$8.61	$0.00	$40.66	$5.52	15.71%
Small	525	121	404	30%	2.4		$15.00	$12.15	$8.05	$0.00	$12.80	$17.30	$0.00	$65.30	$6.26	10.60%
Medium	983	226	757	32%	4.2		$15.00	$20.75	$15.08	$0.00	$23.91	$32.42	$0.00	$107.16	$6.64	6.61%
Large	1,611	371	1,240	35%	6.3		$15.00	$31.55	$24.71	$0.00	$39.25	$53.11	$0.00	$163.62	$6.24	3.96%
XLg	2,681	617	2,064	38%	9.7		$15.00	$48.70	$41.13	$0.00	$65.28	$88.40	$0.00	$258.51	$4.23	1.66%
AnnAvg	1,008	232	776	33%	4.2		$15.00	$21.20	$15.46	$0.00	$24.55	$33.24	$0.00	$109.45	$6.67	6.49%
SumAvg	1,195	275	920	33%	4.9		$15.00	$24.45	$18.33	$0.00	$29.10	$39.40	$0.00	$126.28	$6.60	5.51%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE - SUPER PEAK

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
	Winter	0.1	0.9				$11.50	$0.025000	$0.035000	$0.035000	$0.001140	$0.150000	$0.038700	-$0.002139	
	Summer											$0.170000	$0.039700		
Xsm	150	15	135	150	0	0	$11.50	$3.75	$0.00	$0.00	$0.17	$2.25	$5.22	-$0.32	$22.57
Small	286	29	257	286	0	0	$11.50	$7.15	$0.00	$0.00	$0.33	$4.29	$9.96	-$0.61	$32.62
Medium	641	64	577	400	241	0	$11.50	$10.00	$8.44	$0.00	$0.73	$9.62	$22.33	-$1.37	$61.25
Large	1,043	104	939	400	600	43	$11.50	$10.00	$21.00	$1.51	$1.19	$15.65	$36.33	-$2.23	$94.95
XLg	1,810	181	1,629	400	600	810	$11.50	$10.00	$21.00	$28.35	$2.06	$27.15	$63.04	-$3.87	$159.23
AnnAvg	1,008	101	907	400	600	8	$11.50	$10.00	$21.00	$0.28	$1.15	$15.12	$35.11	-$2.16	$92.00
Avg Win	801	80	721	400	401	0	$11.50	$10.00	$14.02	$0.00	$0.91	$12.01	$27.89	-$1.71	$74.62

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+							
	Winter						$15.00	$0.030100	$0.037500	$0.037500	$0.000000	$0.159790	$0.040810	0.000%			
	Summer											$0.159790	$0.040810			$ Change	% Change
Xsm	150	15	135	150	0	0	$15.00	$4.52	$0.00	$0.00	$0.00	$2.40	$5.51	$0.00	$27.43	$4.86	21.53%
Small	286	29	257	286	0	0	$15.00	$8.61	$0.00	$0.00	$0.00	$4.57	$10.50	$0.00	$38.68	$6.06	18.58%
Medium	641	64	577	400	241	0	$15.00	$12.04	$9.04	$0.00	$0.00	$10.24	$23.54	$0.00	$69.86	$8.61	14.06%
Large	1,043	104	939	400	600	43	$15.00	$12.04	$22.50	$1.61	$0.00	$16.67	$38.31	$0.00	$106.13	$11.18	11.77%
XLg	1,810	181	1,629	400	600	810	$15.00	$12.04	$22.50	$30.38	$0.00	$28.92	$66.48	$0.00	$175.32	$16.09	10.10%
AnnAvg	1,008	101	907	400	600	8	$15.00	$12.04	$22.50	$0.30	$0.00	$16.11	$37.03	$0.00	$102.98	$10.98	11.93%
AvgWin	801	80	721	400	401	0	$15.00	$12.04	$15.02	$0.00	$0.00	$12.79	$29.41	$0.00	$84.26	$9.64	12.92%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE - SUPER PEAK

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
	Winter						$11.50	$0.025000	$0.035000	$0.035000	$0.001140	$0.150000	$0.038700	-$0.002139	
	Summer	0.14	0.86									$0.170000	$0.039700		
Xsm	261	37	224	261	0	0	$11.50	$6.53	$0.00	$0.00	$0.30	$6.21	$8.91	-$0.56	$32.89
Small	525	74	452	400	125	0	$11.50	$10.00	$4.38	$0.00	$0.60	$12.50	$17.92	-$1.12	$55.78
Medium	983	138	845	400	583	0	$11.50	$10.00	$20.41	$0.00	$1.12	$23.40	$33.56	-$2.10	$97.89
Large	1,611	226	1,385	400	600	611	$11.50	$10.00	$21.00	$21.39	$1.84	$38.34	$55.00	-$3.45	$155.62
XLg	2,681	375	2,306	400	600	1,681	$11.50	$10.00	$21.00	$58.84	$3.06	$63.81	$91.53	-$5.74	$254.00
AnnAvg	1,008	141	867	400	600	8	$11.50	$10.00	$21.00	$0.28	$1.15	$23.99	$34.42	-$2.16	$100.18
AvgSum	1,195	167	1,027	400	600	195	$11.50	$10.00	$21.00	$6.82	$1.36	$28.43	$40.79	-$2.56	$117.34

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+							
	Winter						$15.00	$0.030100	$0.037500	$0.037500	$0.000000	$0.159790	$0.040810				
	Summer	0.14	0.86									$0.159790	$0.040810	0.000%			
Xsm	261	37	224	261	0	0	$15.00	$7.86	$0.00	$0.00	$0.00	$5.84	$9.16	$0.00	$37.86	$4.97	15.11%
Small	525	74	452	400	125	0	$15.00	$12.04	$4.69	$0.00	$0.00	$11.74	$18.43	$0.00	$61.90	$6.12	10.98%
Medium	983	138	845	400	583	0	$15.00	$12.04	$21.86	$0.00	$0.00	$21.99	$34.50	$0.00	$105.39	$7.50	7.66%
Large	1,611	226	1,385	400	600	611	$15.00	$12.04	$22.50	$22.91	$0.00	$36.04	$56.54	$0.00	$165.03	$9.41	6.04%
XLg	2,681	375	2,306	400	600	1,681	$15.00	$12.04	$22.50	$63.04	$0.00	$59.98	$94.09	$0.00	$266.65	$12.65	4.98%
AnnAvg	1,008	141	867	400	600	8	$15.00	$12.04	$22.50	$0.30	$0.00	$22.55	$35.38	$0.00	$107.77	$7.59	7.57%
AvgSum	1,195	167	1,027	400	600	195	$15.00	$12.04	$22.50	$7.30	$0.00	$26.73	$41.93	$0.00	$125.50	$8.16	6.95%

	Net Bill	$ Change	% Change
Current Annual	$1,151.78		
Proposed Annual	$1,258.56	$106.78	9.27%

SMALL GENERAL SERVICE

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery kWh			Basic Service Charge	Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill
		1-400	401-7500	7501+		1-400	401-7500	7501+				
					$14.50	$0.030176	$0.041042	$0.076042	$0.001140	$0.058241	-$0.002139	
Xsm	200	200	0	0	$14.50	$6.04	$0.00	$0.00	$0.23	$11.65	-$0.43	$31.99
Small	350	350	0	0	$14.50	$10.56	$0.00	$0.00	$0.40	$20.38	-$0.75	$45.09
Medium	561	400	161	0	$14.50	$12.07	$6.61	$0.00	$0.64	$32.67	-$1.20	$65.29
Large	1,447	400	1,047	0	$14.50	$12.07	$42.97	$0.00	$1.65	$84.27	-$3.10	$152.36
XLg	4,078	400	3,678	0	$14.50	$12.07	$150.95	$0.00	$4.65	$237.51	-$8.72	$410.96
Mean	1,131	400	731	0	$14.50	$12.07	$30.00	$0.00	$1.29	$65.87	-$2.42	$121.31
sum	1,277	400	877	0	$14.50	$12.07	$36.00	$0.00	$1.46	$74.39	-$2.73	$135.69
win	980	400	580	0	$14.50	$12.07	$23.82	$0.00	$1.12	$57.10	-$2.10	$106.51
Annual												$1,453.20

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery kWh			Basic Service Charge	Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		1-400	401-7500	7501+		1-400	401-7500	7501+						
					$30.00	$0.030000	$0.039900	$0.077300	$0.000000	$0.053290	0.000%			
Xsm	200	200	0	0	$30.00	$6.00	$0.00	$0.00	$0.00	$10.66	$0.00	$46.66	$14.67	45.85%
Small	350	350	0	0	$30.00	$10.50	$0.00	$0.00	$0.00	$18.65	$0.00	$59.15	$14.06	31.18%
Medium	561	400	161	0	$30.00	$12.00	$6.42	$0.00	$0.00	$29.90	$0.00	$78.32	$13.03	19.96%
Large	1,447	400	1,047	0	$30.00	$12.00	$41.78	$0.00	$0.00	$77.11	$0.00	$160.89	$8.53	5.60%
XLg	4,078	400	3,678	0	$30.00	$12.00	$146.75	$0.00	$0.00	$217.32	$0.00	$406.07	-$4.89	-1.19%
Mean	1,131	400	731	0	$30.00	$12.00	$29.17	$0.00	$0.00	$60.27	$0.00	$131.44	$10.13	8.35%
sum	1,277	400	877	0	$30.00	$12.00	$35.00	$0.00	$0.00	$68.07	$0.00	$145.07	$9.38	6.91%
win	980	400	580	0	$30.00	$12.00	$23.16	$0.00	$0.00	$52.25	$0.00	$117.41	$10.90	10.23%
Annual												$1,574.88	$121.68	8.37%

WINTER

SMALL GENERAL SERVICE DEMAND

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery kWh 1-400	Delivery kWh 401-7500	Delivery kWh 7501+	Basic Service Charge	Delivery (kWh) 1-400	Delivery (kWh) 401-7500	Delivery (kWh) 7501+	TCA	Base Fuel	PPFAC	Net Bill
							$30.00	$0.030000	$0.039900	$0.077300	$0.000000	$0.053290	$0.000000	
Xsm	34%	0.7	173	173	0	0	$30.00	$5.19	$0.00	$0.00	$0.00	$9.22	$0.00	$44.41
Small	36%	1.2	303	303	0	0	$30.00	$9.09	$0.00	$0.00	$0.00	$16.15	$0.00	$55.24
Medium	38%	1.8	486	400	86	0	$30.00	$12.00	$3.43	$0.00	$0.00	$25.90	$0.00	$71.33
Large	41%	4.2	1,254	400	854	0	$30.00	$12.00	$34.07	$0.00	$0.00	$66.83	$0.00	$142.90
XLg	46%	10.6	3,535	400	3,135	0	$30.00	$12.00	$125.09	$0.00	$0.00	$188.38	$0.00	$355.47
AnnAvg	41%	3.8	1,131	400	731	0	$30.00	$12.00	$29.17	$0.00	$0.00	$60.27	$0.00	$131.44
WinAvg	40%	3.3	980	400	580	0	$30.00	$12.00	$23.16	$0.00	$0.00	$52.25	$0.00	$117.41

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh) On-Peak	Delivery (kWh) Off-Peak	Basic Service Charge	Delivery All kW	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
						30.00	5.05	$0.015970	$0.000000						
	Winter			0.30	0.70					$0.096800	$0.040036	0.000%			
	Summer									$0.097800	$0.045800				
Xsm	34%	0.7	173	53	120	$30.00	$3.54	$2.76	$0.00	$5.09	$4.82	$0.00	$46.21	$1.80	4.06%
Small	36%	1.2	303	92	211	$30.00	$6.06	$4.84	$0.00	$8.92	$8.44	$0.00	$58.26	$3.02	5.47%
Medium	38%	1.8	486	148	338	$30.00	$9.09	$7.76	$0.00	$14.30	$13.54	$0.00	$74.69	$3.36	4.71%
Large	41%	4.2	1,254	381	873	$30.00	$21.21	$20.03	$0.00	$36.90	$34.94	$0.00	$143.08	$0.18	0.13%
XLg	46%	10.6	3,535	1,075	2,460	$30.00	$53.53	$56.45	$0.00	$104.02	$98.50	$0.00	$342.50	-$12.97	-3.65%
AnnAvg	41%	3.8	1,131	344	787	$30.00	$19.19	$18.06	$0.00	$33.28	$31.52	$0.00	$132.05	$0.61	0.47%
WinAvg	40%	3.3	980	298	682	$30.00	$16.67	$15.66	$0.00	$28.85	$27.32	$0.00	$118.50	$1.09	0.93%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE DEMAND

SUMMER

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery kWh			Basic Service Charge	Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill
				1-400	401-7500	7501+		1-400	401-7500	7501+				
							$30.00	$0.030000	$0.039900	$0.077300	$0.000000	$0.053290	$0.000000	
Xsm	35%	0.9	226	226	0	0	$30.00	$6.78	$0.00	$0.00	$0.00	$12.04	$0.00	$48.82
Small	37%	1.5	395	395	0	0	$30.00	$11.85	$0.00	$0.00	$0.00	$21.05	$0.00	$62.90
Medium	39%	2.3	634	400	234	0	$30.00	$12.00	$9.34	$0.00	$0.00	$33.79	$0.00	$85.12
Large	42%	5.3	1,634	400	1,234	0	$30.00	$12.00	$49.24	$0.00	$0.00	$87.08	$0.00	$178.31
XLg	47%	13.5	4,605	400	4,205	0	$30.00	$12.00	$167.78	$0.00	$0.00	$245.40	$0.00	$455.18
AnnAvg	41%	3.8	1,131	400	731	0	$30.00	$12.00	$29.17	$0.00	$0.00	$60.27	$0.00	$131.44
SumAvg	41%	4.2	1,277	400	877	0	$30.00	$12.00	$35.00	$0.00	$0.00	$68.07	$0.00	$145.07

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery		TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak		30.00	All kW	All kWh		On-Peak	Off-Peak				
							30.00	5.05	$0.015970	$0.000000						
	Winter										$0.096800	$0.040036				
	Summer			0.27	0.73						$0.097800	$0.045800	0.000%			
Xsm	35%	0.9	226	60	166		$30.00	$4.55	$3.61	$0.00	$5.86	$7.61	$0.00	$51.63	$2.81	5.75%
Small	37%	1.5	395	105	290		$30.00	$7.58	$6.31	$0.00	$10.24	$13.30	$0.00	$67.43	$4.53	7.20%
Medium	39%	2.3	634	168	466		$30.00	$11.62	$10.12	$0.00	$16.43	$21.34	$0.00	$89.51	$4.39	5.15%
Large	42%	5.3	1,634	433	1,201		$30.00	$26.77	$26.09	$0.00	$42.35	$55.00	$0.00	$180.21	$1.90	1.06%
XLg	47%	13.5	4,605	1,220	3,385		$30.00	$68.18	$73.54	$0.00	$119.36	$155.01	$0.00	$446.09	-$9.09	-2.00%
AnnAvg	41%	3.8	1,131	300	831		$30.00	$19.19	$18.06	$0.00	$29.31	$38.07	$0.00	$134.63	$3.19	2.43%
SumAvg	41%	4.2	1,277	339	939		$30.00	$21.21	$20.40	$0.00	$33.11	$43.00	$0.00	$147.72	$2.65	1.83%

Notes: 1. This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

WINTER

SMALL GENERAL SERVICE DEMAND

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Total kWh	Delivery kWh			Basic Service Charge	Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill
				1-400	401-7500	7501+		1-400	401-7500	7501+				
							$14.50	$0.030176	$0.041042	$0.076042	$0.001140	$0.058241	-$0.002139	
Xsm	34%	0.7	173	173	0	0	$14.50	$5.22	$0.00	$0.00	$0.20	$10.08	-$0.37	$29.62
Small	36%	1.2	303	303	0	0	$14.50	$9.14	$0.00	$0.00	$0.35	$17.65	-$0.65	$40.99
Medium	38%	1.8	486	400	86	0	$14.50	$12.07	$3.53	$0.00	$0.55	$28.31	-$1.04	$57.92
Large	41%	4.2	1,254	400	854	0	$14.50	$12.07	$35.05	$0.00	$1.43	$73.03	-$2.68	$133.40
XLg	46%	10.6	3,535	400	3,135	0	$14.50	$12.07	$128.67	$0.00	$4.03	$205.88	-$7.56	$357.59
AnnAvg	41%	3.8	1,131	400	731	0	$14.50	$12.07	$30.00	$0.00	$1.29	$65.87	-$2.42	$121.31
WinAvg	40%	3.3	980	400	580	0	$14.50	$12.07	$23.82	$0.00	$1.12	$57.10	-$2.10	$106.52

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery		TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak			All kW	All kWh							
							30.00	5.05	$0.015970	$0.000000	On-Peak	Off-Peak				
	Winter			0.30	0.70						$0.096800	$0.040036	0.000%			
	Summer										$0.097800	$0.045800				
Xsm	34%	0.7	173	53	120		$30.00	$3.54	$2.76	$0.00	$5.09	$4.82	$0.00	$46.21	$16.59	55.99%
Small	36%	1.2	303	92	211		$30.00	$5.86	$4.84	$0.00	$8.92	$8.44	$0.00	$58.06	$17.07	41.65%
Medium	38%	1.8	486	148	338		$30.00	$8.94	$7.76	$0.00	$14.30	$13.54	$0.00	$74.54	$16.62	28.70%
Large	41%	4.2	1,254	381	873		$30.00	$21.06	$20.03	$0.00	$36.90	$34.94	$0.00	$142.93	$9.53	7.14%
XLg	46%	10.6	3,535	1,075	2,460		$30.00	$53.73	$56.45	$0.00	$104.02	$98.50	$0.00	$342.70	-$14.89	-4.16%
AnnAvg	41%	3.8	1,131	344	787		$30.00	$19.19	$18.06	$0.00	$33.28	$31.52	$0.00	$132.05	$10.74	8.85%
WinAvg	40%	3.3	980	298	682		$30.00	$16.87	$15.66	$0.00	$28.85	$27.32	$0.00	$118.70	$12.18	11.44%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE DEMAND

SUMMER

	BILL IMPACTS CURRENT RATES													
	Load Factor	Demand (kW)	Total kWh	Delivery kWh			Basic Service Charge	Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill
								1-400	401-7500	7501+				
				1-400	401-7500	7501+	$14.50	$0.030176	$0.041042	$0.076042	$0.001140	$0.058241	-$0.002139	
Xsm	35%	0.9	226	226	0	0	$14.50	$6.82	$0.00	$0.00	$0.26	$13.16	-$0.48	$34.26
Small	37%	1.5	395	395	0	0	$14.50	$11.92	$0.00	$0.00	$0.45	$23.01	-$0.85	$49.03
Medium	39%	2.3	634	400	234	0	$14.50	$12.07	$9.60	$0.00	$0.72	$36.92	-$1.36	$72.47
Large	42%	5.3	1,634	400	1,234	0	$14.50	$12.07	$50.65	$0.00	$1.86	$95.17	-$3.50	$170.75
XLg	47%	13.5	4,605	400	4,205	0	$14.50	$12.07	$172.58	$0.00	$5.25	$268.20	-$9.85	$462.75
AnnAvg	41%	3.8	1,131	400	731	0	$14.50	$12.07	$30.00	$0.00	$1.29	$65.87	-$2.42	$121.31
SumAvg	41%	4.3	1,277	400	877	0	$14.50	$12.07	$36.00	$0.00	$1.46	$74.39	-$2.73	$135.69

	BILL IMPACTS PROPOSED RATES															
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery		TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak			All kW	All kWh							
							30.00	5.05	$0.015970	$0.000000	On-Peak	Off-Peak				
	Winter										$0.096800	$0.040036				
	Summer			0.27	0.73						$0.097800	$0.045800	0.000%			
Xsm	35%	0.9	226	60	166		$30.00	$4.49	$3.61	$0.00	$5.86	$7.61	$0.00	$51.57	$17.31	50.54%
Small	37%	1.5	395	105	290		$30.00	$7.42	$6.31	$0.00	$10.24	$13.30	$0.00	$67.27	$18.24	37.20%
Medium	39%	2.3	634	168	466		$30.00	$11.41	$10.12	$0.00	$16.43	$21.34	$0.00	$89.30	$16.83	23.23%
Large	42%	5.3	1,634	433	1,201		$30.00	$26.77	$26.09	$0.00	$42.35	$55.00	$0.00	$180.21	$9.46	5.54%
XLg	47%	13.5	4,605	1,220	3,385		$30.00	$68.23	$73.54	$0.00	$119.36	$155.01	$0.00	$446.14	-$16.61	-3.59%
AnnAvg	41%	3.8	1,131	300	831		$30.00	$19.19	$18.06	$0.00	$29.31	$38.07	$0.00	$134.63	$13.32	10.98%
SumAvg	41%	4.3	1,277	339	939		$30.00	$21.46	$20.40	$0.00	$33.11	$43.00	$0.00	$147.97	$12.28	9.05%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

SMALL GENERAL SERVICE RATE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23					$16.50	$0.030176	$0.043176	$0.076042	$0.001140	$0.129605	$0.031385	-$0.002139	
	Summer	0.18										$0.129605	$0.039605		
Xsm	394	91	303	394	0	0	$16.50	$11.87	$0.00	$0.00	$0.45	$11.73	$9.51	-$0.84	$49.22
Small	636	146	490	400	236	0	$16.50	$12.07	$10.19	$0.00	$0.73	$18.96	$15.37	-$1.36	$72.46
Medium	1633	376	1,257	400	1,233	0	$16.50	$12.07	$53.24	$0.00	$1.86	$48.68	$39.46	-$3.49	$168.32
Large	2,328	535	1,793	400	1,928	0	$16.50	$12.07	$83.24	$0.00	$2.65	$69.40	$56.26	-$4.98	$235.14
XLg	3,091	711	2,380	400	2,691	0	$16.50	$12.07	$116.19	$0.00	$3.52	$92.14	$74.70	-$6.61	$308.51
WinAvg	1,551	357	1,194	400	1,151	0	$16.50	$12.07	$49.70	$0.00	$1.77	$46.24	$37.48	-$3.32	$160.44

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+							
	Winter	0.23					$30.00	$0.030000	$0.039900	$0.077300	$0.000000	$0.108800	$0.040036	0.000%			
	Summer	0.18										$0.109800	$0.045800				
Xsm	394	91	303	394	0	0	$30.00	$11.81	$0.00	$0.00	$0.00	$9.85	$12.13	$0.00	$63.79	$14.57	29.61%
Small	636	146	490	400	236	0	$30.00	$12.00	$9.42	$0.00	$0.00	$15.92	$19.61	$0.00	$86.95	$14.49	20.00%
Medium	1,633	376	1,257	400	1,233	0	$30.00	$12.00	$49.20	$0.00	$0.00	$40.86	$50.34	$0.00	$182.40	$14.08	8.37%
Large	2,328	535	1,793	400	1,928	0	$30.00	$12.00	$76.93	$0.00	$0.00	$58.26	$71.77	$0.00	$248.96	$13.82	5.88%
XLg	3,091	711	2,380	400	2,691	0	$30.00	$12.00	$107.37	$0.00	$0.00	$77.35	$95.29	$0.00	$322.01	$13.50	4.38%
WinAvg	1,551	357	1,194	400	1,151	0	$30.00	$12.00	$45.93	$0.00	$0.00	$38.81	$47.82	$0.00	$174.56	$14.12	8.80%

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

SMALL GENERAL SERVICE RATE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23					$16.50	$0.030176	$0.043176	$0.076042	$0.001140	$0.129605	$0.031385	-$0.002139	
	Summer	0.18										$0.129605	$0.039605		
Xsm	781	141	640	400	381	0	$16.50	$12.07	$16.45	$0.00	$0.89	$18.22	$25.36	-$1.67	$87.82
Small	1220	220	1,000	400	820	0	$16.50	$12.07	$35.40	$0.00	$1.39	$28.46	$39.62	-$2.61	$130.83
Medium	2350	423	1,927	400	1,950	0	$16.50	$12.07	$84.17	$0.00	$2.68	$54.81	$76.30	-$5.03	$241.50
Large	3,078	554	2,524	400	2,678	0	$16.50	$12.07	$115.63	$0.00	$3.51	$71.81	$99.96	-$6.58	$312.90
XLg	3,640	655	2,985	400	3,240	0	$16.50	$12.07	$139.89	$0.00	$4.15	$84.92	$118.21	-$7.79	$367.95
SumAvg	2,256	406	1,850	400	1,856	0	$16.50	$12.07	$80.15	$0.00	$2.57	$52.64	$73.28	-$4.83	$232.38

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+							
	Winter	0.23					$30.00	$0.030000	$0.039900	$0.077300	$0.000000	$0.108800	$0.040036				
	Summer	0.18										$0.109800	$0.045800	0.000%		$ Change	% Change
Xsm	781	141	640	400	381	0	$30.00	$12.00	$15.20	$0.00	$0.00	$15.44	$29.33	$0.00	$101.97	$14.15	16.11%
Small	1,220	220	1,000	400	820	0	$30.00	$12.00	$32.72	$0.00	$0.00	$24.11	$45.82	$0.00	$144.65	$13.82	10.56%
Medium	2,350	423	1,927	400	1,950	0	$30.00	$12.00	$77.79	$0.00	$0.00	$46.44	$88.24	$0.00	$254.47	$12.97	5.37%
Large	3,078	554	2,524	400	2,678	0	$30.00	$12.00	$106.85	$0.00	$0.00	$60.83	$115.60	$0.00	$325.28	$12.38	3.96%
XLg	3,640	655	2,985	400	3,240	0	$30.00	$12.00	$129.28	$0.00	$0.00	$71.94	$136.70	$0.00	$379.92	$11.97	3.25%
SumAvg	2,256	406	1,850	400	1,856	0	$30.00	$12.00	$74.07	$0.00	$0.00	$44.59	$84.74	$0.00	$245.40	$13.02	5.60%

															$ Change	% Change
Current Annual														$2,356.95		
Proposed Annual														$2,519.76	$162.81	6.91%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE RATE TIME OF USE DEMAND

WINTER

	BILL IMPACTS PROPOSED SGS-TOU RATES														
	Energy (kWh)	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23					$30.00	$0.030000	$0.039900	$0.077300	$0.000000	$0.108800	$0.040036	0.000%	
	Summer	0.18										$0.109800	$0.045800		
Xsm	394	91	303	394	0	0	$30.00	$11.81	$0.00	$0.00	$0.00	$9.85	$12.13	$0.00	$63.79
Small	636	146	490	400	236	0	$30.00	$12.00	$9.42	$0.00	$0.00	$15.92	$19.61	$0.00	$86.95
Medium	1633	376	1,257	400	1,233	0	$30.00	$12.00	$49.20	$0.00	$0.00	$40.86	$50.34	$0.00	$182.40
Large	2,328	535	1,793	400	1,928	0	$30.00	$12.00	$76.93	$0.00	$0.00	$58.26	$71.77	$0.00	$248.96
XLg	3,091	711	2,380	400	2,691	0	$30.00	$12.00	$107.37	$0.00	$0.00	$77.35	$95.29	$0.00	$322.01
WinAvg	1,551	357	1,194	400	1,151	0	$30.00	$12.00	$45.93	$0.00	$0.00	$38.81	$47.82	$0.00	$174.56

	BILL IMPACTS PROPOSED RATES																
	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)			Basic Service Charge	Delivery		TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
									All kW	All kWh							
		On-Peak	Off-Peak					30.00	5.05	$0.015970	$0.000000	On-Peak	Off-Peak				
	Winter	0.23										$0.096800	$0.040036	0.000%			
	Summer	0.18										$0.097800	$0.045800				
Xsm	394	91	303	37%	1.5			$30.00	$7.58	$6.28	$0.00	$8.76	$12.13	$0.00	$64.75	$0.96	1.50%
Small	636	146	490	39%	2.3			$30.00	$11.62	$10.16	$0.00	$14.16	$19.61	$0.00	$85.55	-$1.40	-1.61%
Medium	1633	376	1,257	42%	5.3			$30.00	$26.77	$26.08	$0.00	$36.36	$50.34	$0.00	$169.55	-$12.85	-7.04%
Large	2,328	535	1,793	44%	7.3			$30.00	$36.87	$37.18	$0.00	$51.83	$71.77	$0.00	$227.65	-$21.31	-8.56%
XLg	3,091	711	2,380	45%	9.4			$30.00	$47.47	$49.36	$0.00	$68.82	$95.29	$0.00	$290.94	-$31.07	-9.65%
WinAvg	1,551	357	1,194	42%	5.1			$30.00	$25.76	$24.77	$0.00	$34.53	$47.82	$0.00	$162.88	-$11.68	-6.69%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE RATE TIME OF USE DEMAND

SUMMER

BILL IMPACTS PROPOSED SGS-TOU RATES

	Energy (kWh)	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23					$30.00	$0.030000	$0.039900	$0.077300	$0.000000	$0.108800	$0.040036		
	Summer	0.18										$0.109800	$0.045800	0.000%	
Xsm	781	141	640	400	381	0	$30.00	$12.00	$15.20	$0.00	$0.00	$15.44	$29.33	$0.00	$101.97
Small	1220	220	1,000	400	820	0	$30.00	$12.00	$32.72	$0.00	$0.00	$24.11	$45.82	$0.00	$144.65
Medium	2350	423	1,927	400	1,950	0	$30.00	$12.00	$77.79	$0.00	$0.00	$46.44	$88.24	$0.00	$254.47
Large	3,078	554	2,524	400	2,678	0	$30.00	$12.00	$106.85	$0.00	$0.00	$60.83	$115.60	$0.00	$325.28
XLg	3,640	655	2,985	400	3,240	0	$30.00	$12.00	$129.28	$0.00	$0.00	$71.94	$136.70	$0.00	$379.92
SumAvg	2,256	406	1,850	400	1,856	0	$30.00	$12.00	$74.07	$0.00	$0.00	$44.59	$84.74	$0.00	$245.40

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)			Basic Service Charge	Delivery All kW	Delivery All kWh	TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak					30.00	5.05	$0.015970	$0.000000	On-Peak	Off-Peak				
	Winter	0.23										$0.096800	$0.040036				
	Summer	0.18										$0.097800	$0.045800	0.000%			
Xsm	781	141	640	39%	2.7			$30.00	$13.64	$12.47	$0.00	$13.75	$29.33	$0.00	$99.19	-$2.78	-2.73%
Small	1,220	220	1,000	41%	4.1			$30.00	$20.71	$19.48	$0.00	$21.48	$45.82	$0.00	$137.49	-$7.16	-4.95%
Medium	2,350	423	1,927	44%	7.4			$30.00	$37.37	$37.52	$0.00	$41.36	$88.24	$0.00	$234.49	-$19.98	-7.85%
Large	3,078	554	2,524	45%	9.4			$30.00	$47.47	$49.16	$0.00	$54.19	$115.60	$0.00	$296.42	-$28.86	-8.87%
XLg	3,640	655	2,985	46%	10.9			$30.00	$55.05	$58.13	$0.00	$64.08	$136.70	$0.00	$343.96	-$35.96	-9.47%
SumAvg	2,256	406	1,850	44%	7.1			$30.00	$35.86	$36.03	$0.00	$39.72	$84.74	$0.00	$226.35	-$19.05	-7.76%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

															$ Change	% Change
Current Annual														$2,519.76		
Proposed Annual														$2,335.38	($184.38)	-7.32%

SMALL GENERAL SERVICE RATE TIME OF USE DEMAND

WINTER

BILL IMPACTS CURRENT RATES

	Energy (kWh)	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23					$16.50	$0.030176	$0.043176	$0.076042	$0.001140	$0.129605	$0.031385	-$0.002139	
	Summer	0.18										$0.129605	$0.039605		
Xsm	394	91	303	394	0	0	$16.50	$11.87	$0.00	$0.00	$0.45	$11.73	$9.51	($0.84)	$49.22
Small	636	146	490	400	236	0	$16.50	$12.07	$10.19	$0.00	$0.73	$18.96	$15.37	($1.36)	$72.46
Medium	1,633	376	1,257	400	1,233	0	$16.50	$12.07	$53.24	$0.00	$1.86	$48.68	$39.46	($3.49)	$168.32
Large	2,328	535	1,793	400	1,928	0	$16.50	$12.07	$83.24	$0.00	$2.65	$69.40	$56.26	($4.98)	$235.14
XLg	3,091	711	2,380	400	2,691	0	$16.50	$12.07	$116.19	$0.00	$3.52	$92.14	$74.70	($6.61)	$308.51
WinAvg	1,551	357	1,194	400	1,151	0	$16.50	$12.07	$49.70	$0.00	$1.77	$46.24	$37.48	($3.32)	$160.44

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)			Basic Service Charge	Delivery		TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
									All kW	All kWh							
		On-Peak	Off-Peak					30.00	5.05	$0.015970	$0.000000	On-Peak	Off-Peak				
	Winter	0.23										$0.096800	$0.040036	0.000%			
	Summer	0.18										$0.097800	$0.045800				
Xsm	394	91	303	37%	1.5			$30.00	$7.58	$6.28	$0.00	$8.76	$12.13	$0.00	$64.75	$15.53	31.55%
Small	636	146	490	39%	2.3			$30.00	$11.62	$10.16	$0.00	$14.16	$19.61	$0.00	$85.55	$13.09	18.07%
Medium	1,633	376	1,257	42%	5.3			$30.00	$26.77	$26.08	$0.00	$36.36	$50.34	$0.00	$169.55	$1.23	0.73%
Large	2,328	535	1,793	44%	7.3			$30.00	$36.87	$37.18	$0.00	$51.83	$71.77	$0.00	$227.65	-$7.49	-3.19%
XLg	3,091	711	2,380	45%	9.4			$30.00	$47.47	$49.36	$0.00	$68.82	$95.29	$0.00	$290.94	-$17.57	-5.70%
WinAvg	1,551	357	1,194	42%	5.1			$30.00	$25.76	$24.77	$0.00	$34.53	$47.82	$0.00	$162.88	$2.44	1.52%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE RATE TIME OF USE DEMAND

SUMMER

BILL IMPACTS CURRENT RATES

	Energy (kWh)	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23					$16.50	$0.030176	$0.043176	$0.076042	$0.001140	$0.129605	$0.031385		
	Summer	0.18										$0.129605	$0.039605	-$0.002139	
Xsm	781	141	640	400	381	0	$16.50	$12.07	$16.45	$0.00	$0.89	$18.22	$25.36	($1.67)	$87.82
Small	1,220	220	1,000	400	820	0	$16.50	$12.07	$35.40	$0.00	$1.39	$28.46	$39.62	($2.61)	$130.83
Medium	2,350	423	1,927	400	1,950	0	$16.50	$12.07	$84.17	$0.00	$2.68	$54.81	$76.30	($5.03)	$241.50
Large	3,078	554	2,524	400	2,678	0	$16.50	$12.07	$115.63	$0.00	$3.51	$71.81	$99.96	($6.58)	$312.90
XLg	3,640	655	2,985	400	3,240	0	$16.50	$12.07	$139.89	$0.00	$4.15	$84.92	$118.21	($7.79)	$367.95
SumAvg	2,256	406	1,850	400	1,856	0	$16.50	$12.07	$80.15	$0.00	$2.57	$52.64	$73.28	($4.83)	$232.38

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)			Basic Service Charge	Delivery		TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
									All kW	All kWh							
		On-Peak	Off-Peak					30.00	5.05	$0.015970	$0.000000	On-Peak	Off-Peak				
	Winter	0.23										$0.096800	$0.040036				
	Summer	0.18										$0.097800	$0.045800	0.000%			
Xsm	781	141	640	39%	2.7			$30.00	$13.64	$12.47	$0.00	$13.75	$29.33	$0.00	$99.19	$11.37	12.95%
Small	1,220	220	1,000	41%	4.1			$30.00	$20.71	$19.48	$0.00	$21.48	$45.82	$0.00	$137.49	$6.66	5.09%
Medium	2,350	423	1,927	44%	7.4			$30.00	$37.37	$37.52	$0.00	$41.36	$88.24	$0.00	$234.49	-$7.01	-2.90%
Large	3,078	554	2,524	45%	9.4			$30.00	$47.47	$49.16	$0.00	$54.19	$115.60	$0.00	$296.42	-$16.48	-5.27%
XLg	3,640	655	2,985	46%	10.9			$30.00	$55.05	$58.13	$0.00	$64.08	$136.70	$0.00	$343.96	-$23.99	-6.52%
SumAvg	2,256	406	1,850	44%	7.1			$30.00	$35.86	$36.03	$0.00	$39.72	$84.74	$0.00	$226.35	-$6.03	-2.59%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

INTERRUPTIBLE POWER SERVICE

BILL IMPACTS CURRENT RATES

	Load Factor	Total kWh	Demand (kW)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$18.00	$5.00	$0.019408	$0.432900	0.043760	-$0.002139	
Xsm	40.3%	1,116	66	$18.00	$331.53	$21.65	$28.70	$48.82	-$2.39	$446.32
Small	27.4%	14,651	108	$18.00	$541.23	$284.34	$46.86	$641.11	-$31.34	$1,500.20
Medium	30.7%	29,389	154	$18.00	$768.97	$570.39	$66.58	$1,286.08	-$62.87	$2,647.15
Large	44.3%	71,334	237	$18.00	$1,183.91	$1,384.44	$102.50	$3,121.55	-$152.61	$5,657.79
XLg	58.4%	384,599	887	$18.00	$4,432.94	$7,464.30	$383.80	$16,830.06	-$822.79	$28,306.31
AnnAvg	56.0%	97,708	239	$18.00	$1,195.06	$1,896.33	$103.47	$4,275.72	-$209.03	$7,279.55
AvgWin	52.0%	83,072	219	$18.00	$1,094.21	$1,612.26	$94.74	$3,635.24	-$177.72	$6,276.73
AvgSum	62.0%	112,958	250	$18.00	$1,247.88	$2,192.29	$108.04	$4,943.03	-$241.65	$8,267.58
Annual										$87,265.86

BILL IMPACTS PROPOSED RATES

	Load Factor	Total kWh	Demand (kW)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$75.00	$5.52	$0.014990	$0.000000	$0.053090	0.000%			
Xsm	40.3%	1,116	66	$75.00	$366.01	$16.72	$0.00	$59.23	$0.00	$516.96	$70.64	15.83%
Small	27.4%	14,651	108	$75.00	$597.52	$219.61	$0.00	$777.80	$0.00	$1,669.93	$169.73	11.31%
Medium	30.7%	29,389	154	$75.00	$848.94	$440.55	$0.00	$1,560.28	$0.00	$2,924.77	$277.63	10.49%
Large	44.3%	71,334	237	$75.00	$1,307.03	$1,069.29	$0.00	$3,787.10	$0.00	$6,238.42	$580.63	10.26%
XLg	58.4%	384,599	887	$75.00	$4,893.96	$5,765.14	$0.00	$20,418.37	$0.00	$31,152.47	$2,846.16	10.05%
AnnAvg	56.0%	97,708	239	$75.00	$1,319.35	$1,464.65	$0.00	$5,187.34	$0.00	$8,046.34	$766.79	10.53%
AvgWin	52.0%	83,072	219	$75.00	$1,208.00	$1,245.25	$0.00	$4,410.30	$0.00	$6,938.55	$661.82	10.54%
AvgSum	62.0%	112,958	250	$75.00	$1,377.66	$1,693.24	$0.00	$5,996.93	$0.00	$9,142.83	$875.25	10.59%
Annual										$96,488.28	$9,222.42	10.57%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

MEDIUM GENERAL SERVICE

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$50.00	$12.81	$0.005470	$0.432900	$0.056603	-$0.002139	
Xsm	0.46	20	4,040	$50.00	$256.20	$22.10	$8.66	$228.68	-$8.64	$557.00
Small	0.46	20	6,400	$50.00	$256.20	$35.01	$8.66	$362.26	-$13.69	$698.44
Medium	0.46	36	12,160	$50.00	$463.88	$66.52	$15.68	$688.29	-$26.01	$1,258.36
Large	0.46	80	26,880	$50.00	$1,025.41	$147.03	$34.65	$1,521.49	-$57.51	$2,721.07
Xlarge	0.46	294	98,640	$50.00	$3,762.89	$539.56	$127.16	$5,583.32	-$211.02	$9,851.91
AnnAvg	0.46	80	26,796	$50.00	$1,022.22	$146.58	$34.54	$1,516.76	-$57.33	$2,712.77
sum	0.46	90	30,153	$50.00	$1,150.28	$164.94	$38.87	$1,706.76	-$64.51	$3,046.34
win	0.46	70	23,520	$50.00	$897.22	$128.65	$30.32	$1,331.28	-$50.32	$2,387.15
Annual										$32,600.94

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$100.00	$13.47	$0.005480	$0.000000	$0.053290	0.000%			
Xsm	0.46	20	4,040	$100.00	$269.39	$22.14	$0.00	$215.29	$0.00	$606.82	$49.82	8.9%
Small	0.46	20	6,400	$100.00	$269.39	$35.07	$0.00	$341.06	$0.00	$745.52	$47.08	6.7%
Medium	0.46	36	12,160	$100.00	$487.76	$66.64	$0.00	$648.01	$0.00	$1,302.41	$44.05	3.5%
Large	0.46	80	26,880	$100.00	$1,078.21	$147.30	$0.00	$1,432.44	$0.00	$2,757.95	$36.88	1.4%
Xlarge	0.46	294	98,640	$100.00	$3,956.64	$540.55	$0.00	$5,256.53	$0.00	$9,853.72	$1.81	0.0%
AnnAvg	0.46	80	26,796	$100.00	$1,074.85	$146.84	$0.00	$1,427.98	$0.00	$2,749.67	$36.90	1.4%
sum	0.46	90	30,153	$100.00	$1,209.50	$165.24	$0.00	$1,606.87	$0.00	$3,081.61	$35.27	1.2%
win	0.46	70	23,520	$100.00	$943.41	$128.89	$0.00	$1,253.36	$0.00	$2,425.66	$38.51	1.6%
Annual										$33,043.60	$442.66	1.4%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

MEDIUM GENERAL SERVICE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
		Winter		0.29		$52.00	$12.81	$0.005470	$0.43290	0.114886	0.026168	-$0.002139	
		Summer		0.20						0.114886	0.039886		
Xsm	0.46	27,974	83	8,112	19,862	$52.00	$1,067.14	$153.02	$36.06	$932.01	$519.74	-$59.85	$2,700.12
Small	0.46	28,067	84	8,139	19,928	$52.00	$1,070.69	$153.53	$36.18	$935.11	$521.46	-$60.04	$2,708.93
Medium	0.46	48,453	144	14,051	34,402	$52.00	$1,848.37	$265.04	$62.46	$1,614.31	$900.22	-$103.66	$4,638.74
Large	0.56	62,572	186	18,146	44,426	$52.00	$2,386.98	$342.27	$80.67	$2,084.71	$1,162.54	-$133.86	$5,975.31
XLg	0.66	193,470	576	56,106	137,364	$52.00	$7,380.44	$1,058.28	$249.41	$6,445.83	$3,594.53	-$413.90	$18,366.59
AnnAvg	0.58	69,713	208	20,217	49,496	$52.00	$2,659.39	$381.33	$89.87	$2,322.62	$1,295.22	-$149.14	$6,651.29
AvgWin	0.56	65,673	196	19,045	46,628	$52.00	$2,505.28	$359.23	$84.66	$2,188.02	$1,220.16	-$140.50	$6,268.85

BILL IMPACTS PROPOSED RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
		Winter				$100.00	$13.47	$0.005480	$0.00000	0.101047	0.031690	0.000%			
		Summer								0.114886	0.033500				
Xsm	0.46	27,974	83	8,112	19,862	$100.00	$1,122.09	$153.30	$0.00	$819.74	$629.41	$0.00	$2,824.54	$124.42	4.6%
Small	0.46	28,067	84	8,139	19,928	$100.00	$1,125.82	$153.81	$0.00	$822.46	$631.50	$0.00	$2,833.59	$124.66	4.6%
Medium	0.46	48,453	144	14,051	34,402	$100.00	$1,943.54	$265.52	$0.00	$1,419.85	$1,090.19	$0.00	$4,819.10	$180.36	3.9%
Large	0.56	62,572	186	18,146	44,426	$100.00	$2,509.88	$342.89	$0.00	$1,833.59	$1,407.86	$0.00	$6,194.22	$218.91	3.7%
XLg	0.66	193,470	576	56,106	137,364	$100.00	$7,760.44	$1,060.22	$0.00	$5,669.37	$4,353.06	$0.00	$18,943.09	$576.50	3.1%
AnnAvg	0.58	69,713	208	20,217	49,496	$100.00	$2,796.32	$382.03	$0.00	$2,042.84	$1,568.53	$0.00	$6,889.72	$238.43	3.6%
AvgWin	0.56	65,673	196	19,045	46,628	$100.00	$2,634.27	$359.89	$0.00	$1,924.46	$1,477.64	$0.00	$6,496.26	$227.41	3.6%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

MEDIUM GENERAL SERVICE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
		Winter		0.29		$52.00	$12.81	$0.005470	$0.43290	0.114886	0.026168		
		Summer		0.20						0.114886	0.039886	-$0.002139	
Xsm	0.46	27,974	83	5,595	22,379	$52.00	$1,067.14	$153.02	$36.06	$642.76	$892.62	-$59.85	$2,783.75
Small	0.46	28,067	84	5,613	22,454	$52.00	$1,070.69	$153.53	$36.18	$644.90	$895.58	-$60.04	$2,792.84
Medium	0.46	48,453	144	9,691	38,762	$52.00	$1,848.37	$265.04	$62.46	$1,113.31	$1,546.08	-$103.66	$4,783.60
Large	0.56	62,572	186	12,514	50,058	$52.00	$2,386.98	$342.27	$80.67	$1,437.73	$1,996.60	-$133.86	$6,162.39
XLg	0.66	193,470	576	38,694	154,776	$52.00	$7,380.44	$1,058.28	$249.41	$4,445.40	$6,173.40	-$413.90	$18,945.03
AnnAvg	0.58	69,713	208	13,943	55,770	$52.00	$2,659.39	$381.33	$89.87	$1,601.81	$2,224.46	-$149.14	$6,859.72
AvgSum	0.56	73,609	219	14,722	58,887	$52.00	$2,808.00	$402.64	$94.89	$1,691.32	$2,348.76	-$157.47	$7,240.14

BILL IMPACTS PROPOSED RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
		Winter				$100.00	$13.47	$0.005480	$0.00000	0.101047	0.031690				
		Summer								0.114886	0.033500	0.000%			
Xsm	0.46	27,974	83	5,595	22,379	$100.00	$1,122.09	$153.30	$0.00	$642.76	$749.70	$0.00	$2,767.85	-$15.90	-0.6%
Small	0.46	28,067	84	5,613	22,454	$100.00	$1,125.82	$153.81	$0.00	$644.90	$752.20	$0.00	$2,776.73	-$16.11	-0.6%
Medium	0.46	48,453	144	9,691	38,762	$100.00	$1,943.54	$265.52	$0.00	$1,113.31	$1,298.54	$0.00	$4,720.91	-$62.69	-1.3%
Large	0.56	62,572	186	12,514	50,058	$100.00	$2,509.88	$342.89	$0.00	$1,437.73	$1,676.93	$0.00	$6,067.43	-$94.96	-1.5%
XLg	0.66	193,470	576	38,694	154,776	$100.00	$7,760.44	$1,060.22	$0.00	$4,445.40	$5,185.00	$0.00	$18,551.06	-$393.97	-2.1%
AnnAvg	0.58	69,713	208	13,943	55,770	$100.00	$2,796.32	$382.03	$0.00	$1,601.81	$1,868.31	$0.00	$6,748.47	-$111.25	-1.6%
AvgSum	0.56	73,609	219	14,722	58,887	$100.00	$2,952.58	$403.37	$0.00	$1,691.32	$1,972.71	$0.00	$7,119.98	-$120.16	-1.7%

		$ Change	% Change	
Current Annual		$81,053.94		
Proposed Annual		$81,697.44	$643.50	0.8%

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

LARGE GENERAL SERVICE TO NEW LARGE GENERAL SERVICE

BILL IMPACTS CURRENT RATES - LGS

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$50.00	$12.81	$0.005470	$0.43290	0.056603	-$0.002139	
Xsm	30%	487	108,698	$50.00	$6,238.47	$594.58	$210.82	$6,152.66	-$232.54	$13,013.99
Small	46%	584	200,005	$50.00	$7,486.16	$1,094.03	$252.99	$11,320.89	-$427.88	$19,776.19
Medium	66%	701	344,357	$50.00	$8,983.40	$1,883.63	$303.58	$19,491.61	-$736.69	$29,975.52
Large	75%	842	469,577	$50.00	$10,780.08	$2,568.59	$364.30	$26,579.47	-$1,004.58	$39,337.85
XLg	95%	1,010	713,757	$50.00	$12,936.09	$3,904.25	$437.16	$40,400.80	-$1,526.96	$56,201.34
AnnAvg	54%	768	310,000	$50.00	$9,838.08	$1,695.70	$332.47	$17,546.93	-$663.19	$28,799.99

BILL IMPACTS PROPOSED RATES - LGS

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$300.00	$12.88	$0.005300	$0.00000	$0.053290	0.000%			
Xsm	30%	487	108,698	$300.00	$6,272.56	$576.10	$0.00	$5,792.54	$0.00	$12,941.20	-$72.79	-0.6%
Small	46%	584	200,005	$300.00	$7,527.07	$1,060.03	$0.00	$10,658.27	$0.00	$19,545.37	-$230.83	-1.2%
Medium	66%	701	344,357	$300.00	$9,032.49	$1,825.09	$0.00	$18,350.76	$0.00	$29,508.34	-$467.19	-1.6%
Large	75%	842	469,577	$300.00	$10,838.98	$2,488.76	$0.00	$25,023.76	$0.00	$38,651.50	-$686.35	-1.7%
XLg	95%	1,010	713,757	$300.00	$13,006.78	$3,782.91	$0.00	$38,036.12	$0.00	$55,125.81	-$1,075.53	-1.9%
AnnAvg	54%	768	310,000	$300.00	$9,891.84	$1,643.00	$0.00	$16,519.90	$0.00	$28,354.74	-$445.25	-1.5%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE <69kV TO NEW LARGE GENERAL SERVICE

	BILL IMPACTS CURRENT RATES - LPS <69kV									
	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$1,200.00	$22.00	$0.000462	$0.43290	$0.04188	-$0.002139	
Xsm	44%	747	240,000	$1,200.00	$16,438.36	$110.88	$323.46	$10,051.20	-$513.44	$27,610.46
Small	46%	893	300,000	$1,200.00	$19,654.56	$138.60	$386.75	$12,564.00	-$641.80	$33,302.11
Medium	66%	844	406,600	$1,200.00	$18,566.21	$187.85	$365.33	$17,028.41	-$869.85	$36,477.95
Large	75%	1,553	850,000	$1,200.00	$34,155.25	$392.70	$672.08	$35,598.00	-$1,818.43	$70,199.60
XLg	75%	2,192	1,200,000	$1,200.00	$48,219.18	$554.40	$948.82	$50,256.00	-$2,567.20	$98,611.20
AnnAvg	65%	992	470,630	$1,200.00	$21,820.57	$217.43	$429.37	$19,709.98	-$1,006.83	$42,370.52

	BILL IMPACTS PROPOSED RATES - LPS <69 kV											
	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$300.00	$12.88	$0.005300	$0.00000	$0.053290	0.000%			
Xsm	44%	747	240,000	$300.00	$9,623.91	$1,272.00	$0.00	$12,789.60	$0.00	$23,985.51	-$3,624.95	-13.1%
Small	46%	893	300,000	$300.00	$11,506.85	$1,590.00	$0.00	$15,987.00	$0.00	$29,383.85	-$3,918.26	-11.8%
Medium	66%	844	406,600	$300.00	$10,869.67	$2,154.98	$0.00	$21,667.71	$0.00	$34,992.36	-$1,485.58	-4.1%
Large	75%	1,553	850,000	$300.00	$19,996.35	$4,505.00	$0.00	$45,296.50	$0.00	$70,097.85	-$101.75	-0.1%
XLg	75%	2,192	1,200,000	$300.00	$28,230.14	$6,360.00	$0.00	$63,948.00	$0.00	$98,838.14	$226.94	0.2%
AnnAvg	65%	992	470,630	$300.00	$12,774.95	$2,494.34	$0.00	$25,079.87	$0.00	$40,649.16	-$1,721.36	-4.1%

LARGE POWER SERVICE TIME OF USE <69kV TO NEW LARGE GENERAL SERVICE TIME OF USE

WINTER

	BILL IMPACTS CURRENT RATES											
	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
	Winter		0.16		$1,200.00	$22.00	$0.000462	$0.43290	$0.093880	$0.022105	-$0.002139	
	Summer		0.16						$0.123580	$0.024716		
Small	433,335	1,281	69,334	364,001	$1,200.00	$28,182.00	$200.20	$554.54	$6,509.04	$8,046.25	-$927.05	$43,764.98
Medium	517,000	1,380	82,720	434,280	$1,200.00	$30,360.00	$238.85	$597.40	$7,765.75	$9,599.76	-$1,106.04	$48,655.72
Large	600,000	1,400	96,000	504,000	$1,200.00	$30,800.00	$277.20	$606.06	$9,012.48	$11,140.92	-$1,283.60	$51,753.06
XLg	775,000	1,570	124,000	651,000	$1,200.00	$34,540.00	$358.05	$679.65	$11,641.12	$14,390.36	-$1,657.98	$61,151.20
Mean	642,400	1,430	102,784	539,616	$1,200.00	$31,460.00	$296.79	$619.05	$9,649.36	$11,928.21	-$1,374.31	$53,779.10
AvgWin	627,900	1,416	100,464	527,436	$1,200.00	$31,152.00	$290.09	$612.99	$9,431.56	$11,658.97	-$1,343.29	$53,002.32

	BILL IMPACTS PROPOSED RATES													
	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
	Winter				$300.00	$12.88	$0.005300	$0.00000	$0.139880	$0.034927	0.000%			
	Summer								$0.143771	$0.038600				
Small	433,335	1,281	69,334	364,001	$300.00	$16,499.28	$2,296.68	$0.00	$9,698.38	$12,713.48	$0.00	$41,507.82	-$2,257.16	-5.2%
Medium	517,000	1,380	82,720	434,280	$300.00	$17,774.40	$2,740.10	$0.00	$11,570.87	$15,168.10	$0.00	$47,553.47	-$1,102.25	-2.3%
Large	600,000	1,400	96,000	504,000	$300.00	$18,032.00	$3,180.00	$0.00	$13,428.48	$17,603.21	$0.00	$52,543.69	$790.63	1.5%
XLg	775,000	1,570	124,000	651,000	$300.00	$20,221.60	$4,107.50	$0.00	$17,345.12	$22,737.48	$0.00	$64,711.70	$3,560.50	5.8%
Mean	642,400	1,430	102,784	539,616	$300.00	$18,418.40	$3,404.72	$0.00	$14,377.43	$18,847.17	$0.00	$55,347.72	$1,568.62	2.9%
AvgWin	627,900	1,416	100,464	527,436	$300.00	$18,238.08	$3,327.87	$0.00	$14,052.90	$18,421.76	$0.00	$54,340.61	$1,338.29	2.5%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE TIME OF USE <69kV TO NEW LARGE GENERAL SERVICE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
	Winter		0.16		$1,200.00	$22.00	$0.000462	$0.43290	$0.093880	$0.022105		
	Summer		0.16						$0.123580	$0.024716	-$0.002139	
Small	433,335	1,281	69,334	364,001	$1,200	$28,182.00	$200.20	$554.54	$8,568.25	$8,996.66	-$927.05	$46,774.60
Medium	517,000	1,380	82,720	434,280	$1,200	$30,360.00	$238.85	$597.40	$10,222.54	$10,733.66	-$1,106.04	$52,246.41
Large	600,000	1,400	96,000	504,000	$1,200	$30,800.00	$277.20	$606.06	$11,863.68	$12,456.86	-$1,283.60	$55,920.20
XLg	775,000	1,570	124,000	651,000	$1,200	$34,540.00	$358.05	$679.65	$15,323.92	$16,090.12	-$1,657.98	$66,533.76
Mean	642,400	1,430	102,784	539,616	$1,200	$31,460.00	$296.79	$619.05	$12,702.05	$13,337.15	-$1,374.31	$58,240.73
AvgSum	656,700	1,444	105,072	551,628	$1,200	$31,768.00	$303.40	$625.11	$12,984.80	$13,634.04	-$1,404.90	$59,110.45

BILL IMPACTS PROPOSED RATES

	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
	Winter				$300.00	$12.88	$0.005300	$0.00000	$0.139880	$0.034927				
	Summer								$0.143771	$0.038600	0.000%			
Small	433,335	1,281	69,334	364,001	$300.00	$16,499.28	$2,296.68	$0.00	$9,968.16	$14,050.45	$0.00	$43,114.57	-$3,660.03	-7.8%
Medium	517,000	1,380	82,720	434,280	$300.00	$17,774.40	$2,740.10	$0.00	$11,892.74	$16,763.21	$0.00	$49,470.45	-$2,775.96	-5.3%
Large	600,000	1,400	96,000	504,000	$300.00	$18,032.00	$3,180.00	$0.00	$13,802.02	$19,454.40	$0.00	$54,768.42	-$1,151.78	-2.1%
XLg	775,000	1,570	124,000	651,000	$300.00	$20,221.60	$4,107.50	$0.00	$17,827.60	$25,128.60	$0.00	$67,585.30	$1,051.54	1.6%
Mean	642,400	1,430	102,784	539,616	$300.00	$18,418.40	$3,404.72	$0.00	$14,777.36	$20,829.18	$0.00	$57,729.66	-$511.07	-0.9%
AvgSum	656,700	1,444	105,072	551,628	$300.00	$18,598.72	$3,480.51	$0.00	$15,106.31	$21,292.84	$0.00	$58,778.38	-$332.07	-0.6%

	Net Bill	$ Change	% Change
Current Annual	$672,676.62		
Proposed Annual	$678,713.94	$6,037.32	0.90%

LARGE POWER SERVICE - TRANSMISSION VOLTAGE

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$1,200.00	$17.00	$0.000462	$0.43290	$0.041880	-$0.002139	
Xsm	0.42	506	155,000	$1,200.00	$8,594.26	$71.61	$218.85	$6,491.40	-$331.60	$16,244.52
Small	0.42	1,267	388,500	$1,200.00	$21,541.10	$179.49	$548.54	$16,270.38	-$831.13	$38,908.37
Small	0.46	1,336	448,600	$1,200.00	$22,710.54	$207.25	$578.32	$18,787.37	-$959.70	$42,523.79
Medium	0.75	2,416	1,322,700	$1,200.00	$41,070.14	$611.09	$1,045.84	$55,394.68	-$2,829.70	$96,492.04
Medium	0.75	2,817	1,542,200	$1,200.00	$47,885.66	$712.50	$1,219.39	$64,587.34	-$3,299.28	$112,305.61
Large	0.89	4,775	3,102,500	$1,200.00	$81,179.78	$1,433.36	$2,067.22	$129,932.70	-$6,637.28	$209,175.77
Large	0.89	5,379	3,494,900	$1,200.00	$91,447.28	$1,614.64	$2,328.68	$146,366.41	-$7,476.76	$235,480.26

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$1,500.00	$12.48	$0.000500	$0.00000	$0.049332	0.000%			
Xsm	0.42	506	155,000	$1,500.00	$6,309.20	$77.50	$0.00	$7,646.43	$0.00	$15,533.13	-$711.39	-4.4%
Small	0.42	1,267	388,500	$1,500.00	$15,813.70	$194.25	$0.00	$19,165.41	$0.00	$36,673.36	-$2,235.01	-5.7%
Small	0.46	1,336	448,600	$1,500.00	$16,672.21	$224.30	$0.00	$22,130.26	$0.00	$40,526.77	-$1,997.02	-4.7%
Medium	0.75	2,416	1,322,700	$1,500.00	$30,150.31	$661.35	$0.00	$65,251.21	$0.00	$97,562.87	$1,070.83	1.1%
Medium	0.75	2,817	1,542,200	$1,500.00	$35,153.71	$771.10	$0.00	$76,079.54	$0.00	$113,504.35	$1,198.74	1.1%
Large	0.89	4,775	3,102,500	$1,500.00	$59,595.51	$1,551.25	$0.00	$153,051.99	$0.00	$215,698.75	$6,522.98	3.1%
Large	0.89	5,379	3,494,900	$1,500.00	$67,133.06	$1,747.45	$0.00	$172,409.80	$0.00	$242,790.31	$7,310.06	3.1%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE TIME OF USE >69kV

WINTER

BILL IMPACTS CURRENT RATES

	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill
	Winter				$1,200.00	$17.00	$0.000462	$0.43290	$0.093880	$0.022105	-$0.002139	
	Summer		0.11	0.89					$0.123580	$0.024716		
Small	2,790,000	5,083	306,900	2,483,100	$1,200.00	$86,411.00	$1,288.98	$2,200.43	$28,811.77	$54,888.93	-$5,967.81	$168,833.30
Medium	3,150,000	5,083	346,500	2,803,500	$1,200.00	$86,411.00	$1,455.30	$2,200.43	$32,529.42	$61,971.37	-$6,737.85	$179,029.67
Large	2,115,000	5,083	232,650	1,882,350	$1,200.00	$86,411.00	$977.13	$2,200.43	$21,841.18	$41,609.35	-$4,523.99	$149,715.10
Mean	2,717,000	5,083	298,870	2,418,130	$1,200.00	$86,411.00	$1,255.25	$2,200.43	$28,057.92	$53,452.76	-$5,811.66	$166,765.70
AvgWin	2,726,000	5,083	299,860	2,426,140	$1,200.00	$86,411.00	$1,259.41	$2,200.43	$28,150.86	$53,629.82	-$5,830.91	$167,020.61

BILL IMPACTS PROPOSED RATES

	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill	$ Change	% Change
	Winter				$1,500.00	$12.48	$0.000500	$0.00000	$0.092110	$0.030410	0.000%			
	Summer								$0.125200	$0.033410				
Small	2,790,000	5,083	306,900	2,483,100	$1,500.00	$63,435.84	$1,395.00	$0.00	$28,268.56	$75,511.07	$0.00	$170,110.47	$1,277.17	0.76%
Medium	3,150,000	5,083	346,500	2,803,500	$1,500.00	$63,435.84	$1,575.00	$0.00	$31,916.12	$85,254.44	$0.00	$183,681.40	$4,651.73	2.60%
Large	2,115,000	5,083	232,650	1,882,350	$1,500.00	$63,435.84	$1,057.50	$0.00	$21,429.39	$57,242.26	$0.00	$144,664.99	-$5,050.11	-3.37%
Mean	2,717,000	5,083	298,870	2,418,130	$1,500.00	$63,435.84	$1,358.50	$0.00	$27,528.92	$73,535.33	$0.00	$167,358.59	$592.89	0.36%
AvgWin	2,726,000	5,083	299,860	2,426,140	$1,500.00	$63,435.84	$1,363.00	$0.00	$27,620.10	$73,778.92	$0.00	$167,697.86	$677.25	0.41%

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

LARGE POWER SERVICE TIME OF USE >69kV

SUMMER

BILL IMPACTS CURRENT RATES

	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill
	Winter				$1,200.00	$17.00	$0.000462	$0.43290	$0.093880	$0.022105		
	Summer		0.11	0.89					$0.123580	$0.024716	-$0.002139	
Small	2,790,000	5,083	306,900	2,483,100	$1,200.00	$86,411.00	$1,288.98	$2,200.43	$37,926.70	$61,372.30	-$5,967.81	$184,431.60
Medium	3,150,000	5,083	346,500	2,803,500	$1,200.00	$86,411.00	$1,455.30	$2,200.43	$42,820.47	$69,291.31	-$6,737.85	$196,640.66
Large	2,115,000	5,083	232,650	1,882,350	$1,200.00	$86,411.00	$977.13	$2,200.43	$28,750.89	$46,524.16	-$4,523.99	$161,539.62
Mean	2,717,000	5,083	298,870	2,418,130	$1,200.00	$86,411.00	$1,255.25	$2,200.43	$36,934.35	$59,766.50	-$5,811.66	$181,955.87
AvgSum	2,790,000	5,083	311,600	2,478,400	$1,200.00	$86,411.00	$1,288.98	$2,200.43	$38,507.53	$61,256.13	-$5,967.81	$184,896.26

BILL IMPACTS PROPOSED RATES

	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill	$ Change	% Change
	Winter				$1,500.00	$12.48	$0.000500	$0.00000	$0.092110	$0.030410				
	Summer								$0.125200	$0.033410	0.000%			
Small	2,790,000	5,083	306,900	2,483,100	$1,500	$63,436	$1,395	$0.00	$38,423.88	$82,960.37	$0.00	$187,715	$3,283.49	1.78%
Medium	3,150,000	5,083	346,500	2,803,500	$1,500	$63,436	$1,575	$0.00	$43,381.80	$93,664.94	$0.00	$203,558	$6,916.92	3.52%
Large	2,115,000	5,083	232,650	1,882,350	$1,500	$63,436	$1,058	$0.00	$29,127.78	$62,889.31	$0.00	$158,010	-$3,529.19	-2.18%
Mean	2,717,000	5,083	298,870	2,418,130	$1,500	$63,436	$1,359	$0.00	$37,418.52	$80,789.72	$0.00	$184,503	$2,546.71	1.40%
AvgSum	2,790,000	5,083	311,600	2,478,400	$1,500	$63,436	$1,395	$0.00	$39,012.32	$82,803.34	$0.00	$188,147	$3,250.24	1.76%

	Total Net Bill	$ Change	% Change
Current Annual	$2,111,501		
Proposed Annual	$2,135,066	$23,565	1.12%

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

LIGHTING SERVICE

Description	Old Rate	New Rate	
New 30' Wood Pole (Class 6) - Overhead	$4.34	$4.34	$0.91
New 30' Metal or Fiberglass - Overhead	$8.66	$8.66	
Existing Wood Pole - Underground	$2.18	$2.18	
New 30' Wood Pole (Class 6) - Underground	$6.52	$6.52	
New 30' Metal or Fiberglass - Underground	$10.81	$10.81	
Wattage, per Watt	$0.051681	$0.058707	
Base Power Supply	$0.010113	$0.014505	
PPFAC	-$0.002139	0.000%	

		Proration
New Rate Days	28	100%
Old Rate Days	0	0%

Total Days	28
Total kWh billed	150

Customer Bill	Current Rates	Proposed Rates	$Change	%Change
100 Watt	$5.17	$5.87	$0.70	13.54%
150 Watt	$7.75	$8.81	$1.06	13.68%
200 Watt	$10.34	$11.74	$1.40	13.54%
250 Watt	$12.92	$14.68	$1.76	13.62%
400 Watt	$20.67	$23.48	$2.81	13.59%
Existing Wood Pole OH	$4.34	$4.34	$0.00	0.00%
New 30' Wood Pole OH	$8.66	$8.66	$0.00	0.00%
New 30' Metal or FG OH	$2.18	$2.18	$0.00	0.00%
Existing Wood Pole UG	$6.52	$6.52	$0.00	0.00%
New 30' Wood Pole UG	$10.81	$10.81	$0.00	0.00%
New 30' Metal or FG UG	$0.05	$0.06	$0.01	13.59%
Base Power Supply	$1.52	$2.18	$0.66	43.42%
PPFAC	($0.32)	$0.00	$0.32	-100.00%
Typical	$13.29	$15.33	$2.04	15.35%

Detail of Services Billed	Wattage	Units Billed
100 Watt	100	1
150 Watt	150	1
200 Watt	200	1
250 Watt	250	1
400 Watt	400	1
Existing Wood Pole OH		5
New 30' Wood Pole OH		0
New 30' Metal or FG OH		0
Existing Wood Pole UG		0
New 30' Wood Pole UG		0
New 30' Metal or FG UG		0

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>
DOUG LITTLE - INTERIM CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
VACANT

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

EXHIBIT UNSE-34 admitted

Rebuttal Testimony of

H. Edwin Overcast

on Behalf of

UNS Electric, Inc.

January 19, 2016

Table of Contents

Appendices:

Exhibits:

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. H. Edwin Overcast. My business address is P. O. Box 2946, McDonough, Georgia 30253.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am a Director, Black & Veatch Management Consulting, LLC.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. A detailed summary of my educational and professional experience is provided in Appendix A to this testimony. I have a B. A. degree in economics from King College and a Ph.D. degree in economics from Virginia Polytechnic Institute and State University. My fields of study include microeconomic theory, industrial organization and public finance. I have been employed in the energy industry for more than 40 years in various rate, regulatory and planning positions. My industry employers include the Tennessee Valley Authority, Northeast Utilities (an electric and gas holding company) and AGL Resources (a gas holding company). I have been employed as a utility consultant since 1998 providing rate, regulatory, strategic and other consulting services to utility clients. In my various positions, I have testified before state and federal regulatory bodies, Canadian provincial regulatory bodies, state and federal legislative bodies and in various courts. I have previously testified before the Federal Energy Regulatory Commission ("FERC") on a number of electric, gas pipeline and oil pipeline issues.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am testifying on behalf of UNS Electric (UNSE or the Company)

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION?

A. No.

Q. PLEASE PROVIDE A LIST OF STATE AND CANADIAN JURISDICTIONS IN WHICH YOU HAVE TESTIFIED.

A. I have testified in Connecticut, Massachusetts, Georgia, Tennessee, Montana, Missouri, New York, Ohio, Michigan, Arkansas, New Jersey, Oklahoma, Kansas and Maryland. In Canada I have testified before the Ontario Energy Board, the Alberta Energy and Utilities Board, the New Brunswick Energy and Utilities Board and the British Columbia Utilities Commission. My testimony has been related to issues such as cost of service, rate design, prudence, rate of return, regulatory risk, performance based regulation, competition and unbundling.

Q. DURING YOUR CAREER HAVE YOU MADE PRESENTATIONS TO ENERGY RELATED TRAINING AND OTHER PROGRAMS?

A. Yes. I have been an instructor for the Edison Electric Institute's Rate Fundamentals and Advanced Rate School related to cost of service. I have been an instructor in both the American Gas Association's Rate Fundamentals and Advanced Rate courses. I have been an instructor for the Southern Gas Association's Intermediate Rate Course and for the RMEL providing training related to regulation. I have made numerous presentations to trade association meetings including the EEI Rate Committee, the AGA Rate Committee, the AEIC Load Research Committee, SURFA and other industry sponsored programs. I have made presentations to NARUC events and events sponsored by academic institutions. I have also written broadly on various subjects related to utility regulation, including issues related to the integration of distributed generation into a utility system and the design of rates for the 21st century.

Q. HAVE YOU PROVIDED EXPERT TESTIMONY ON COST OF SERVICE AND RATE DESIGN RELATED TO NET METERING, RATES FOR DISTRIBUTED GENERATION (DG) CUSTOMERS AND DEVELOPMENT OF RATES FOR PURCHASE OF ENERGY FROM DG CUSTOMERS?

A. Yes. My testimony in Maryland addressed these issues and more related to cost of service, rate design, net metering impacts and the impact of purchasing excess generation at the full SOS rate. In that testimony, I developed specific measures of the level of subsidy created by net metering and demonstrated that the Commission's net metering rule resulted in undue discrimination based on the factual circumstances for the utility.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. My rebuttal testimony addresses a number of areas related to the economics of DG from the perspective of the utility, its customers and economic efficiency. Specifically, I respond to issues raised by the Commission Staff, Vote Solar (VS), Western Resource Advocates (WRA), The Alliance for Solar Choice (TASC), Residential Utility Consumer Office (RUCO), Southwest Energy Efficiency Project (SWEEP) and Arizona Utility Ratepayers Alliance (AURA). I address the following issues as discussed by some or all of these parties:

- the cost to serve a partial requirements DG customer – specifically a Solar DG customer compared to a full requirements customer in the residential class;
- the subsidies being provided to DG customers under the current rate design and net metering tariff;
- the economic and regulatory rationale for a separate rate for a DG customer that requires different treatment than a standard customer until such time as utility rates are fully unbundled and customers are classed based on the cost causing characteristics of their service;
- the economic and regulatory basis for multi-part rates including customer charges, demand charges and time differentiated energy charges;
- the efficacy of demand based rates for all customer classes and how such rates will impact customers;
- the ability of customers to respond to more complex price signals,
- the role of fairness, efficiency and gradualism in developing and implementing new mandatory rate designs; mitigation of adverse impacts during the rate design transition;
- the reason all customers should be on the same rates with any special considerations (CARES customers for example) should have mitigation outside of the rate structure per se;
- the customers who choose to use the utility system in ways that result in high unit costs (low load factor customers for example) should pay the full costs imposed on the system under the cost causation principle and the matching principle of rates;

- the importance of multi-step transition plans to assure timely and efficient implementation of the best rate design for all customer classes in an expeditious manner; and

Finally, I provide support for the central themes in the Staff's proposal while at the same timing recommending transition steps necessary to that proposal to match costs and revenues and to minimize the impact of changes over time. Although these issues as they relate to net metering, three part rates and the inefficiency and intraclass subsidy from inverted block rates are all closely intertwined as is evident in the various sections, I have discussed the topics in separate sections to identify the focus on a particular issue.

Q. HOW IS YOUR REBUTTAL TESTIMONY ORGANIZED?

A. My testimony is organized in sections beginning with this introduction that includes a summary of my recommendations and the individual sections as follows:

II. Economics of Serving Full and Partial Requirements Service Customers

III. Separate Rate Treatment for DG Customers

IV. The Economic Rationale for Multi-Part Rates

V. Customer Response to More Complex Price Signals

VI. Customer Cost Analysis

VII. The Concepts of Fairness, Efficiency and Gradualism

VIII. Serving All Customers in a Class under the Same Rate Schedule

IX. Conclusions

Q. PLEASE BRIEFLY SUMMARIZE THE EVIDENCE YOU HAVE PROVIDED IN THIS REBUTTAL TESTIMONY.

A. My evidence shows that the combination of two-part rate with a low customer charge and inclining block rates coupled with the banking provision of net metering for residential DG customers results in customers with equal costs paying far different annual bills for the services they use. The subsidy to residential DG customers results from both fixed costs and variable energy costs. The magnitude of the subsidy totals about $91 per kW of installed solar DG annually under UNS Electric's current rates.

I explain why the two-part rate cannot be just and reasonable when serving both full requirements customers and partial requirements customers such as DG. I use metered data from two solar facilities to show that solar customers generation patterns result in more off-peak energy on an annual basis than on peak and do not even avoid the average cost of energy much less the full cost of Base Power and the associated PPFAC adjustments. I show how a multi-part rate reflects cost causation more accurately and when unbundled will be consistent with the principles of cost causation and matching costs and revenues with a proper design.

I show how a separate rate for solar DG customers is not discriminatory and in fact is the best option for eliminating the current undue discrimination that favors these customers. The separate rate is necessary for all new solar customers even if the Commission accepts the Staff proposal for a three-part rate because the issue of unjust subsidy will continue until the rate is fully implemented.

I provide a discussion of the appropriate components of customer costs that include much more than what some witnesses refer to as the Basic Customer Method. I note that this method is not even discussed as an option in the NARUC Electric Cost Allocation Manual and with good reason. It is simply not a reflection of costs caused by customers. Using the minimum system as UNSE has done in its cost study results in class costs that more closely match cost causation. Rates should reflect the higher customer charges that result from the cost of service study and more where marginal cost based price signals do not produce the revenue requirements.

Finally, I provide a discussion of the appropriate rate for CARES customers and discuss the adverse impact on low income customers from proposals that collect fixed customer related costs in kWh charges.

II. ECONOMICS OF SERVING FULL AND PARTIAL REQUIREMENTS SERVICE CUSTOMERS

Q. PLEASE DEFINE THE TERMS FULL AND PARTIAL REQUIREMENTS CUSTOMERS.

A. A full requirements service customer is a customer who elects to use the full bundle of utility services on a continuous basis and acquires no utility related services from another provider. In the case of an electric customer this means that the customer uses the full scope of production, transmission, distribution and customer services from the utility in a seamless package represented by the delivery of capacity and energy to the customer as required by the customer. A partial requirements service customer is a customer who elects to select the particular components of the utility service to be used when the customer elects to use the utility service and to use other non-utility sources for all or a portion of the some of the standard utility services to meet his demand for energy or capacity or some combination of the two requirements.

Partial requirements customers essentially are former full requirements customers who elect to use the utility for services such as back-up/standby service, maintenance service or supplemental service or some combination of all of these services. Partial requirements customers differ both from full requirements customers and from each other depending on the non-utility services they purchase because the demand and energy load shapes the utility must stand ready to serve differ and in some case differ dramatically. For example, some partial requirements services provide baseload service leaving the utility to provide supplemental peaking services and may be viewed as low load factor customers for the utility. Other partial requirements services are peaking in nature and leave the utility to provide baseload service and may be viewed as high load factor customers for the utility. Each different service has different cost characteristics based on the cost the utility incurs to serve the customer.

Every solar DG customer differs from customers who use cogeneration and cogeneration customers differ based on technology. They also differ based on the underlying total hourly demand for electricity. For example, when a residential customer changes from full requirements to partial requirements the underlying load of the dwelling does not change nor do the local facilities installed to serve that customer. As an example, the utility cannot change the service line or the transformer to serve that customer because those were sized to serve the maximum load of the customer whenever it occurs. The load measured in kWh and kW imposed on the utility does change however. The customer may use less energy but may still require the same kW capacity for delivery service and may even require the same capacity for production and transmission depending on a number of factors associated with the customer's non-utility supply source. Since different technologies have different supply characteristics every different source will have a different impact. In some cases, that impact is a function of system characteristics in others it is a function of technology or some of both. If a new customer comes on the system as a partial requirements customer, the utility system planners must provide for the maximum service that a partial requirements customer may impose when the customer's non-utility source of supply is not available. The important point is that one cannot assume that cost causation for the selected utility services will change when the customer elects partial requirements service and in some cases it may even increase. To determine cost causation requires an understanding of the type and timing of the services provided by the utility. Finally, it is critically important to recognize that utility capacity requirements are not the same for each component of utility service. Appendix B to this rebuttal testimony is a copy of my white paper "*Smart Rates for Smart Utilities*" that provides a detailed discussion of many of the concepts related to unbundled rates and the necessity for each rate component.

Several examples will illustrate this point. For a utility that is winter peaking the peaks occur either in the early morning driven by electric heating load or in the evening driven by miscellaneous appliance load. In either case solar DG contributes nothing to reducing any of the capacity requirements of the utility. If the utility was winter peaking for load but summer peaking for capacity the solar facilities would contribute to the summer peak capacity based on the expected peak load hour occurring typically in the afternoon. Solar DG would have no impact of the capacity cost for distribution and portions of transmission plant. The summer peak load contribution may or may not have a capacity value depending on whether the net peak load demand actually shifts to a later hour. This is the concept labeled as the "Duck Curve" in California where the peak load shifts to a later hour in the day where there is no solar generation.

Since the issue of capacity savings cannot be determined based solely on one measure of capacity as discussed later in this rebuttal testimony, it is impossible to conclude that there are capacity benefits for each measure of capacity- production, transmission and distribution- for partial requirements service. The capacity obligation associated with delivery to the DG customer is typically the same as for a full requirements customer and is based on the expected load of the premise which may and usually does occur outside the peak load period.

Q. HAVE YOU DEVELOPED DATA TO SHOW HOW THE SOLAR DG CUSTOMERS OUTPUT COMPARES WITH THE SYSTEM LOAD ON A MONTHLY BASIS?

A. Yes. I have attached Exhibit HEO-1 that provides a month by month comparison of system loads and solar output based on actual metered load data for two different solar power facilities-a single axis tracking solar generating facility (La Senita) and a fixed axis south facing facility (Rio Rico) and the retail load of UNSE Electric during 2015. As the exhibit shows production in the winter months of November to April uniformly misses the high load hours and tends to be the highest in the load valleys. In the summer months for the tracking facility, solar production declines as load rises in the afternoon and since the system peak hour occurs at 5 PM, solar output is uniformly declining at that hour for both facilities. The data also shows that the tracking facility has both longer hours of production and a higher rate of production in the summer hours near the peak than the south facing facility which is more consistent with a rooftop solar DG facility. Finally, as solar penetration continues to increase the potential for the Duck Curve impact to shift the evening peak hour as it does in California also grows thus assuring no distribution capacity peak savings and potentially no transmission or generation capacity savings for solar generation. I should also point out that increased solar penetration also reduces avoided energy costs.

I have also prepared Exhibit HEO-2 that shows for the same two facilities that the hours of maximum output occur in hours other than the highest marginal cost hours in both the winter and the summer. This means that excess generation sold back to the utility occurs on average at times when the avoided energy cost is less than the average energy cost and less than the marginal cost of energy used by solar DG customers to meet the load in excess of solar DG. Exhibit HEO-3 shows that in the winter and the summer (2015) the value of the energy avoided cost for these two facilities is uniformly less than the Base Power Costs (the unbundled rate component for energy) plus PPFAC determined under the actual PPFAC calculation on an hourly basis in every hour of the day on average. For UNSE the gap in energy cost is at least $16 per MWh in the summer and over $24 dollars per MWh in the winter. Added to this difference is the fact that on the peak day in the summer the ambient temperature is so high that the efficiency of the solar generation is reduced by over 7% in the Nogales and Kingman areas and by over 10% in Havasu. We also know that the maximum solar output actually occurs in the shoulder months (when customer loads are lowest) so there is a further subsidy associated with the banking provision. Under the banking provision the subsidy is the difference between the avoided marginal cost and the Base Power plus the PPFAC rate applied when those kWh are actually consumed by the customer and when the excess kWhs are produced. That subsidy is in excess of three cents per kWh. This evidence not only shows that net metering creates large subsidies with respect to energy costs but that without modifications to net metering and separate rate treatment for partial requirements DG customers there is no opportunity for rates to be just and reasonable and not unduly discriminatory.

III. SEPARATE RATE TREATMENT FOR DG CUSTOMERS

Q. WHAT IS THE RATIONALE FOR TREATING PARTIAL REQUIREMENTS CUSTOMERS IN A SEPARATE CLASS FROM FULL REQUIREMENTS CUSTOMERS?

A. Under two-part rates the assumption that is required for rates to reflect cost causation is that load characteristics are relatively homogeneous as to cost causation and to load patterns. Relative homogeneity existed when kWh rates were first used for residential customers in the late 19th century because the only electric load was lighting. The demand was a function of the number of fixtures and kWh consumption was a function of average operating hours. Thus a simple two-part rate with a customer or access charge and a flat kWh charge represented a reasonable rate because the cause of cost and the load characteristics were the same. Over time, the end use load profiles of residential customers has changed and electric rates evolved to reflect different load characteristics through declining block rates and through separate rate classes for different end-use residential loads such as all electric rates or special provisions for specific end-uses such as a water heating block for customers with electric water heating. The trend away from these rate provisions to flat and inverted rate designs and fewer special provisions made rates less cost based as end-use load profiles continued to be more diverse because larger groups of customers were served under rates that were simple but not capable of reflecting costs for less homogeneous groups. With the addition of partial requirements customers within a class, customers are no longer homogeneous as the following table illustrates by comparing two identical premises with the same demographic characteristics:

Table 1

Comparison of Full and Partial Requirements Customers

Measures	Full Requirements	Partial Requirements
Customer Maximum Demand	10 kW	10 kW
Annual Energy Consumption	35,040 kWh	35,040 kWh
Annual Billed kWh	35,040 kWh	17,047 kWh*
Load Factor	40 %	19.4%

* Based on 35,040 kWh less the energy produced by a 10 kW Solar PV system operating at a 20.54% annual capacity factor.

From a cost perspective the delivery cost is the same for these two customers. The difference in cost recovery under the current UNSE Electric rates is calculated in Table 2 below based on the current local delivery component (Delivery Service- Energy) of the current unbundled rate alone.

Table 2

Customer Revenue Under Rate Res-01

Billing Determinants	Local Delivery	Full Requirements	Partial Requirements
Customer	12	$120.00	$120.00
0-400 kWh	4800	$25.30	$25.30
401-1000 kWh	7200	$146.31	$146.31
Over 1000 kWh			
Full Requirements	23040	$563.79	
Partial Requirements	5047		$123.50
Total Bill		$855.40	$415.11
Difference		$440.29	

Total Bill is the annual bill for the Delivery Service- Energy rate only.

Table 2 shows that the annual delivery subsidy under current rates is over $44 per kW of installed solar capacity. This subsidy is based on equal treatment for equal cost causing delivery characteristics and is not tied directly to a measure of the cost subsidy which may be even larger as a result of the inverted block rate where excess costs are recovered from the largest no-DG customers. In addition, on the basis of cost causation there will be subsidy in the generation and transmission portion of the rate simply because the solar PV capacity of 10 kW will not be coincident with the system peak demand as shown by the monthly charts in Exhibit HEO-1. Instead, only a portion of the installed kW will be coincident with an afternoon peak. The coincident amount will be between 2% and 24% of the installed kW on average and even lower on a peak day because of the extreme temperature. This implies a further subsidy for the remainder of the base charge. It should be noted that this result occurs because of the current price signal based on energy that incents the customer to install a system that maximizes energy production without regard to the capacity value of the solar facility[1]. This means that solar panels would face south in the Northern Hemisphere to maximize energy production instead of west to maximize summer peaking capacity contribution.[2] In that event the capacity contribution of solar and the later timing of the solar customers class NCP would result in no distribution cost savings and potentially even higher distribution costs associated with the class NCP for DG customers occurring at a later hour. Under the most favorable circumstances a 5 kW solar facility would reduce the class NCP by about 0.5 kW and that would not be enough to result in smaller distribution facilities such as a transformer or conductor even if all of the customers using the same equipment had installed solar DG.

There is also the issue of a potential subsidy under the energy cost component of the base rate. That subsidy would result from the load pattern of the solar power delivery that does not occur in uniform high cost hours. In fact, solar output is maximized in hours outside the peak period as defined in the residential TOU rate in both the winter and the summer. Since the winter off-peak period represents the majority of operating hours in that season and represents only 33% of the summer peak operating hours it is reasonable to conclude that the solar energy value is less that the base energy charge.

[1] A generation and transmission on-peak demand charge would provide an incentive to consider both the capacity and the energy value when installing solar and also for investments in EE.

[2] See for example "9% of solar homes are doing something utilities love. Will others follow?", OPOWER Blog December 1, 2014.

The average hourly marginal cost for UNSE in 2015 was also well below the average fuel and purchased power costs and lower than the total fuel and related costs reflected in the Base Power portion of the rate as shown in Table 3.

Table 3

Fuel and Purchased Power Cost Comparisons 2015

Cost Category	Cost per MWH
Marginal Cost	$24.77
Rio Rico Solar Avoided Energy Cost	$27.00
La Senita Avoided Energy Cost	$27.40
Average Fuel and Purchased Power Cost	$37.43
Actual Base plus PPFAC Cost	$53.53

Table 3 also includes the average avoided energy cost for hourly metered solar facilities that further demonstrates that solar DG does not avoid the average cost of energy but a lesser amount because of the effort to maximize energy rather than the capacity value of generation for Rio Rico. La Senita has a higher capacity value because it is a single axis tracking facility and even then still avoids less than the average energy costs. The avoided generation capacity cost for solar DG assuming capacity was needed immediately is less than one cent per kWh and far less than that if capacity is needed further out in the future. Since marginal cost is the measure of the avoided costs and the average fuel and purchased power cost represents the energy component of power costs the $10 difference represents a subsidy in the energy component of the base energy costs. The full subsidy based on Base Power plus PPFAC is the difference between the

Rio Rico avoided cost of $27 per MWh and the Base Power plus PPFAC of $53.53 or $26.53 per MWh. The subsidy is larger for the full Base Power plus PPFAC because that includes fixed costs for purchased power that are not avoided and hedging costs as well. The energy related subsidy based on the fixed axis solar DG would be about $47.72 per kW of solar capacity[3]. This subsidy also creates arbitrage for solar DG customers who consume energy in high cost summer hours and sell energy in low cost, off-peak winter, spring and fall hours as discussed above. The impact would be a subsidy larger than the difference between average energy costs and marginal energy costs on an annual basis.

Q. PLEASE SUMMARIZE THE TOTAL SUBSIDY RECEIVED BY A RESIDENTIAL DG CUSTOMER.

A. The total subsidy from the Delivery Services rate and the Base Power is over $91[4] per kW and more than $642 per year for the average 7 kW solar DG facility. This amount does not include the arbitrage benefit noted above when customers consume solar DG customers consume power in summer periods and deliver the energy in low cost daylight hours in the winter season.

All of this evidence suggests that with a two part rate and net metering with banking can never result in just and reasonable rates for partial requirement DG customers. The only possible alternative to treat partial requirements, DG customers equitably is a separate rate class with a three-part rate. Further, the excess kWhs should not be banked but should be purchased at a market based rate. This solution is practical

[3] 8760 hours times a capacity factor of 20.54% times $26.53

[4] Delivery subsidy of $44.03 plus energy subsidy of $47.72 is $91.75

immediately and need not wait until there is a general rate redesign for all residential customers. It also illustrates that there is a substantial subsidy inherent in net metering because the use of self-generated kWhs saves the DG customer more than the system saves by an amount that over-values the DG contribution. This is part of the reason that commissions and others are developing Value of Solar (VOS) and a buy all sell all rate as a substitute for net metering. I might also note that from an economic perspective solar DG is not a least cost solution for the utility and its customers when community solar has much lower installed capacity costs because of economies of scale. Furthermore, I disagree with any of the critics of this approach that may suggest that eliminating the banking feature is in effect violating the concept of "netting" which is fundamental to the net metering concept. The fact that the Company is simply crediting back energy produced by DG at a market value different from the total delivered cost of power to the customer does not change the net metering that the customer sees relative to its own use of energy. There are valid cost based reasons including the provision under PURPA that makes adoption of any standard including net metering satisfy the principle of equitable rate treatment for customers.

Q. ARE THERE OTHER ISSUES THAT MAKE THE SEPARATE TREATMENT OF DG CUSTOMERS NECESSARY IN THE CURRENT PROCEEDING?

A. Yes. The unequal treatment of customers who have the same costs but provide very different levels of revenue to recover those costs is a perfect demonstration of undue discrimination and that the current rates are no longer just and reasonable as the result of a combination of the net metering provisions and the current inverted block two-part rate with a low monthly basic customer charge. Essentially, the recovery of almost all of the fixed cost of service in volumetric charges results in undue discrimination when the customers in a class are no longer homogeneous. The ACC Staff correctly recognizes the nature of this problem when Staff witness Broderick states "DG customers avoid paying a significant portion of the utility's fixed costs even though DG customers continue to use the grid."[5] Staff witness Solganick reached the same conclusion and states "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."[6] Witness Solganick also notes that "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."[7] When the difference in charges is as large as 106% of a customer's base delivery bill the subsidy is no longer just and reasonable and constitutes undue discrimination. The only practical solution is to eliminate the net metering provision and recover costs under a separate rate schedule for partial requirements customers as proposed by UNSE. Further, it is imperative to flatten the three tiered energy rate to two tiers as proposed by the Company to send a better price signal to other potential DG customers. This is a necessary step as UNSE moves over time to TOU based fuel charges and demand based charges for fixed costs.

Q. IS THE STAFF AND UNS ELECTRIC PROPOSAL OF A THREE PART RATE CONSISTENT WITH CURRENT VIEWS ON BEST PRACTICES?

A. The Staff proposal moves toward the adoption of a three-part rate and I will discuss that concept in detail below. It is actually consistent with the best practices approach to

[5] Direct Rate Design Testimony of Thomas Broderick ('Broderick"), page 4, lines 7-9.
[6] Direct Rate Design Testimony of Howard Solganick ("Solganick Rate"), page 7
[7] Ibid. page 9

designing rates for DG as noted by a number of organizations such as e-Labs of the Rocky Mountain Institute who states "These technologies can provide to or require from the grid energy, capacity, and ancillary services based on individual capabilities. But these characteristics vary along many dimensions that are not reflected in block, volumetric rates. For example, when a customer is exposed to a high marginal price tier in an inclining block rate structure, rates can both reinforce and skew the message that price signals should send. Rooftop PV can look more competitive with retail rates based on the higher credit received for energy production."[8] This is the exact conclusion reached above relative to the inefficient orientation of solar panels relative to actual avoided costs because of the energy only price signal.

A report from the MIT Center for Energy and Environmental Policy Research states the following:

> Allocating network costs primarily on the basis of volumetric energy consumption presents inefficiencies in distribution systems evolving to incorporate a growing number of DER and a growing list of new stakeholders. These inefficiencies include: few price signals to incentivize optimal network utilization; cross-subsidization among network users; and business model arbitrage of rate structures.[9]

That same report supports the use of a customer component of the distribution system and demand charges for customers based on the capacity component of the system.[10]

[8] "RATE DESIGN FOR THE DISTRIBUTION EDGE: ELECTRICITY PRICING FOR A DISTRIBUTED RESOURCE FUTURE", e-Lab Rocky Mountain Institute, August 2014, p.15 http://www.rmi.org/elab_rate_design
[9] "A Framework for Redesigning Distribution Network Use of System Charges Under High Penetration of Distributed Energy Resources: New Principles for New Problems" Ignacio Pérez-Arriaga and Ashwini Bharatkumar, October 2014, p.6 https://mitei.mit.edu/system/files/20141028_UOF_DNUoS-FrameworkPaper.pdf
[10] Ibid. p. 16-20

In a report prepared for EEI titled "Retail Cost Recovery and Rate Design" Kenneth Gordon (the former Chairman of both the Massachusetts Department of Public Utilities and the Maine Public Utilities Commission) and Wayne P. Olson make the following statement:

> To the greatest extent possible, customer- or demand-related fixed costs should not be rolled into energy charges. The end-use customer often sees too high a price for energy and too low a price for demand and customer charges. Hence, the customer never receives the economically efficient price signal for either one.[11]

Each of these references correctly recognizes the role of multi-part rates in addressing the issues of efficient pricing and reflecting cost causation. Current rate designs as recognized by UNSE, the Staff and even RUCO recognize to some extent that the current two-part rate for residential customers is inefficient and includes subsidies. The important point is that subsidies resulting from averaging costs in class rates are far different than artificial subsidies that reach the level of undue discrimination as they do in the case of net metering with largely volumetric rates. Average cost subsidies are found in items such as using the average service line costs knowing full well that the customer on the same side of the street as the transformer has a shorter service line than the neighbor across the street. Short of designing rates for each customer, a utility and its regulators must accept some level of intra class subsidy; however, it is incumbent up them to address undue subsidies and discrimination. The subsidies under net metering with two part rates create undue discrimination that needs to be addressed in the current

[11] "Retail Cost Recovery and Rate Design" Kenneth Gordon and Wayne P. Olson, Prepared for the Edison Electric Institute, December 2004, p. viii. See also p. 26.
http://www.ksg.harvard.edu/hepg/Papers/Gordon.Olson.Retail.Cost.Recovery.pdf

case, not postponed and not to wait on implementation of a phased approach to multi-part rates that does little or nothing to address the problem for years to come.

Q. PLEASE DISCUSS THE CLAIM THAT SEPARATE RATE TREATMENT FOR DG IS DISCRIMINATORY.

A. This is a common claim made by solar advocates who want to maintain the extremely favorable treatment (and profitable marketing opportunity created by the current combination of net metering and largely kWh recovery of fixed costs) accorded to solar DG. The best way address this claim is to analyze the meaning of discrimination in the context of regulation. The Merriam-Webster Dictionary defines discrimination as *the practice of unfairly treating a person or group of people differently from other people or groups of people and the ability to understand that one thing is different from another thing.* As applied to solar DG and discussed above customers who become partial requirements customers are clearly different from full requirements customers and in that sense the discrimination is not inconsistent with the basis for designing rates for homogeneous classes of service. While it may be inconvenient for the solar advocates to recognize that solar DG customers differ from full requirements customers the evidence shows that this is precisely the case. The customers are different based on load characteristics and in terms of cost causation. The question becomes: Does singling out these customers for different rate treatment result in those customers being treated unfairly? The simple answer is no. This answer is supported by a review of the evidence as it relates to cost causation and the contribution of these customers to that cost compared to other full requirements customers. This is an empirical question that requires nothing more than the basic analysis of whether the solar DG customers contribute the same revenues toward the costs they cause as other customers who have the same cost causation. As an example of the necessity for empirical investigation the Vote Solar witness Kobor states in response to UNS Electric Data Request 1.28 that "UNSE has not provided evidence that the Company's NEM and non-NEM customers have significantly different consumption patterns greater than the inevitable diversity in consumption within the residential and small commercial classes." This statement is incorrect because UNS Electric provided bill frequency data for residential customers broken out by full requirements customers and by net metering customers. Exhibit HEO- 4 compares both the bill frequency and the cumulative kWh frequency for these two customer groups. Those frequencies demonstrate conclusively that solar DG customers contribute far less revenue for the exact same delivery costs as other customers if for no other reason than 57.16% of net energy billed customers have zero kWh use meaning those customers contribute nothing to cover any distribution related costs and do not even cover the full customer costs. Exhibit HEO-4 shows that about 89% of DG customers' bills are for usage that does not include charges in the third tier of the rate. In contrast about 69% of residential full requirements customers' bills are for usage that does not include the third tier. Exhibit HEO- 4 also shows that the pattern of cumulative kWhs for both full and partial requirement DG customers is nearly identical after net metering. This means that these DG customers are uniformly large users of electricity than full requirements customers.[12] Given that these customers are larger on average, it also means that the customers demand are larger as well. Thus the

[12] This is consistent with economic price signals that provide a third tier incentive for larger customers to invest in DG and experience a higher implied return on investment.

subsidy assuming equal size for DG customers actually underestimates the subsidy for DG.

Since, the only true avoided costs are related to the marginal energy cost and some potential avoided generation capacity costs at less than one cent per kWh based on the coincident peak demand of less than 24% of the rated capacity depending on the peak load hour. (For this conclusion, the concept of the "Duck Curve" has not been considered because it may well eliminate this avoided cost also.) It is the existence of this undue discrimination that solar advocates seek to maintain to their advantage.

Regulatory policy is not required and in fact is prohibited from picking winners and losers when discrimination becomes undue. The goal of efficient regulatory policy is to develop a system of rates and charges for customers so that as they choose between full requirements service and partial requirements service the utility and its other customers are indifferent between those choices. Such a standard requires that the customers who choose different aspects of utility service pay the full costs of the services they choose to use. It is unreasonable for a customer to use a kilowatt hour of electricity that costs six cents to produce and then pay for that kWh by selling the utility a kWh when the utility value of that kWh is three cents but this is what occurs under the net metering banking provision. It is unreasonable for a customer to use the same distribution services as another customer and pay over almost $500 less per year for that delivery service. This later point is also impacted by the fact that the solar DG customer may actually cost more to serve for the same delivery service based on increased day ahead planning reserve requirements and regulation reserve requirements related to generation operation. DG customers also impact the distribution system relative to VAR requirements and reduced life for voltage regulation devices as examples of cost increases. It is reasonable to conclude that the differences between full and partial requirements customers using solar DG are real, empirically verified and thus not discriminatory. It is also reasonable to conclude that separate treatment is a reasonable step to eliminate discrimination between solar DG customers and full requirements customers.

IV. THE ECONOMIC RATIONALE FOR MULTI-PART RATES

Q. PLEASE EXPLAIN THE ECONOMIC RATIONALE FOR MULTI-PART RATES.

A. As noted above, multi-part rates represent the best practices approach to rates that are just and reasonable, equitable and economically efficient. They have been in use successfully since the 1890s for large customers and were not originally used for smaller customers because of the practical metering constraints and the relative homogeneity of smaller customers at the outset of the electric utility business. This is despite the fact that for over 100 years electric utilities have recognized that there are other services provided to customers other than the energy commodity. This is simply because a kWh provided in one hour may not cause the same cost as in another hour hence the need to have time differentiated (TOU) based energy charges. The utility also provides a variety of capacity services for generation, transmission and distribution. The capacity related services have no costs that vary with energy usage hence charging larger users more has no basis in cost causation and directly contributes to the magnitude of the subsidies under net metering without any economic efficiency benefits and based on the economic literature real dead weight losses.[13] It is important to note that customers using the same amount of energy may have very different capacity related requirements. As an example, a large home with central air-conditioning and gas heating and water heating may use the same amount of electricity in a year as a smaller all-electric home. If we assume that the utility is a summer peaking utility like UNSE, we would expect that the larger home would have a higher coincident peak demand than the smaller home and thus higher generation capacity related costs but would have a lower delivery capacity requirement and thus lower distribution related capacity costs. Incidentally, this is why the tiered rate concept is fatally flawed as a price signal because it punishes customers based solely on the usage level despite the fact that total usage is not correlated with each component of capacity cost causation nor is it necessarily correlated with higher energy costs. The smaller heating customer has lower capacity costs for generation and transmission, lower energy costs and only higher delivery demand costs that are lower than the capacity costs for generation and transmission. Thus the Company is correct to eliminate the third tier and the RUCO rationale for keeping the tier is fatally flawed.

Q. HOW DOES A MULTI-PART RATE PROVIDE EFFICIENT PRICE SIGNALS FOR CUSTOMERS?

A. Since energy charges are not adequate for reflecting cost causation (virtually all economists agree that this is the correct objective for rates) it is necessary to understand all of the components that cause costs to be different. It is a fundamental proposition that costs are caused by customers, demand and energy. In fact all cost studies use

[13] See for example "Rationalizing California's Residential Electricity Rates", Posted on September 29, 2014 by Severin Borenstein, https://energyathaas.wordpress.com/2014/09/29/rationalizing-californias-residential-electricity-rates/

these three elements to classify costs. To match pricing with cost causation would require at least three parts- a customer charge, a demand charge and an energy charge. The Commission Staff correctly recognizes that the rate must at least have these three components and this is a valuable starting point for developing cost based rates. However, the Staff proposal does not recognize that the single demand component of a three part rate cannot reflect cost causation for the different components of the functionalized costs that include production, transmission, substations, primary distribution and secondary distribution unless of course the class CP and NCP and the customer NCP are highly correlated. Since we know that will not be true for DG customers and that demographics will cause it not to be true even for full requirements customers there will be a need for at least two measures of demand. For example the Staff recommends an on-peak demand charge to recover the costs of distribution fixed charges. As I have shown the example above and as may be observed by even a casual review of both load research data and the elements of the distribution system compared to the system peak load, customers cause distribution demand costs not based on the coincident peak demand but on non-coincident peak demands. It is common for utilities to have a greater investment in substation capacity than in generation capacity and more transformer capacity then in substation capacity. The reason is simple. There is more load diversity at the system peak load then there is as the loads move closer to customers. In fact, it is not at all uncommon that substation peaks occur at different times and in some cases even different seasons from the system peak. It is even unusual for more than a few substations to peak coincident with the system peak. As with substations, feeder circuits also peak at different times than the substation that serves the feeder. For example, the load research data underlying the UNS Electric 2014 cost of service study and provided to the parties in response to data requests in this case shows that the residential class CP occurs on July 23 at hour ending 4 PM while the class NCP for the same day occurs at hour 6 PM. That hour is not the residential class NCP used to allocate substation capacity for example since that hour occurs at 5 PM on July 24 one day later. The same data shows that the largest residential customer peaked on August 30th at 9 PM; the largest 1% of customers peaked at 5 PM on July 30th; and the largest 25% of customers peaked at 5PM on July 24th coincident with the class NCP. The class NCP values are also smaller than the customer NCP values that impact the design of transformers and feeders. One other observation worth noting is the differences in feeder loading in the summer late afternoon between 4 PM and 6 PM are relatively inconsequential when considered in the context of system planning. That is the hourly loads over the period from mid- afternoon until 8 PM on a peak day are typically within one to two-tenths of a kW difference from high to low. Thus under the Staff proposal of an on-peak demand charge to recover distribution costs the solar DG customers would still avoid paying for some of the capacity costs they cause. The simple solution is to use maximum customer demand whenever it occurs to recover distribution costs. This will solve the subsidy problem for delivery service and do so without any prolonged delay. It will also be easily implemented and result in a lower per unit charge that will be easier to phase in with a lower impact on bills. As rates evolve over time the Staff proposal of an on-peak demand charge based on marginal peak capacity costs may be added as an additional rate component.

Q. HOW WOULD A DISTRIBUTION DEMAND CHARGE BE DETERMINED?

A. First, it will be necessary to set the time interval over which demand is measured. Staff and the Company propose using one hour initially. One hour is the least commonly used interval with both 15 and 30 minute intervals used more often. Ultimately there are a number of reasons for using the 15 minute interval. First, 15 minute intervals are more stable over time so customers do not see large swings in their demand measurements. The 15 minute intervals are also more reflective of cost causation since transformers and circuits have longer life if they do not experience overload conditions with any frequency. Third the shorter interval results in a lower per unit demand charge to recover the distribution related costs. While the same dollars are recovered regardless of the demand interval, the shorter interval benefits both customers and the utility through stable more predictable charges on a monthly basis. Customers also benefit because a one-time peak does not significantly change the bill. Ideally this demand charge would be based on a contract demand rather than a measured demand in the future since this would reflect the sizing of the local facilities installed to serve the customer and would actually be a separate facilities charge. Some utilities have used this approach for demand billed customers. This charge should be properly based on a 100% ratchet to further minimize the charge and reflect cost causation because these costs are a function of the customer's maximum demand whenever it occurs. That is for distribution demand there is no time dimension. In fact, the Staff proposal to collect these costs in a peak period is not cost based and results in both shifting peaks and uneconomic investment in storage to avoid the peak period charge. Once the interval is determined and the charge is based on maximum demand whenever it occurs subject to a 100% ratchet, the kW charge would send the appropriate price signal and would be economically efficient. Under the Staff proposal, a partial requirements customer would still be able to bypass a portion of the delivery system costs that are necessary for serving the customers load since the distribution system still needs to be large enough to serve the load of the premise plus provide in-rush current, frequency regulation, var requirements and standby and supplemental services.

Q. ARE THERE DEMAND CHARGES THAT ARE APPROPRIATELY INCLUDED IN THE PEAK PERIOD?

A. Yes. It is appropriate to include a demand charge for generation capacity in a peak period. That charge should be based on the marginal capacity cost of the utility. In this way, the capacity value of DG and EE are signaled to the customer. This would result in efficient investment in both DG capacity and storage. If the charge exceeds marginal cost as it would if it was designed to recover the embedded costs of generation capacity, it would create subsidies and promote investments in utility resources inconsistent with the least cost of total utility supply service.

The marginal cost of capacity is determined by the least capital intensive addition to the system. That is nominally a combustion turbine and sets the upper bound for avoided costs as it may be lower if another unit is built to satisfy energy constraints. When capacity is not required in the near term, the demand charge will be based on the net present value of the stream of future capacity payments. In determining the on-peak period for this charge consideration must be given to shifting peaks over time and the probability that peak demands that cause the addition of capacity are properly identified because they may not necessarily be in the highest load hours.

It is important to understand that generation demand charges may also be required outside the peak period to recover other embedded costs. In that case, the charge would be based on monthly maximum demand to the extent that it is greater than peak demand.

Q. HOW ARE TRANSMISSION DEMAND COST RECOVERED?

A. Transmission costs are recovered in a variety of charges including congestion charges where marginal energy costs are based on locational marginal price, on-peak demand charges that may be different from the capacity charges and even some costs in the distribution demand charges for load laterals. For UNSE it is likely that the generation laterals and the bulk system will be recovered in the same on-peak period as the generation capacity marginal costs.

Q. THIS SOUNDS MORE COMPLICATED THAN A THREE-PART RATE PROPOSAL. HOW ARE CUSTOMERS TO UNDERSTAND THE BILL?

A. As in the Staff proposal, there is no need to get to the ultimate rate design in the first step. It will be a gradual process done in steps. In fact, I suggest that the first and most important step in this case would be to phase out the tiered rates as proposed by UNSE by eliminating the third tier. In addition, I would remove all of the energy related costs from base rates and recover those costs through a seasonal and time differentiated energy charge. This will partially mitigate the energy subsidy for DG customers since the energy savings from kWhs in the winter and in the low cost periods for the summer will be somewhat reduced. Coupled with a modified net metering tariff that prohibits banking and purchases solar power at a market based rate as proposed by UNSE will also mitigate the inefficient price signals for rooftop solar. I might note here that the proposed market price for excess generation still contains a subsidy for roof top solar simply because the purchase of capacity under the market rate is year round while the purchase of excess generation is likely to be in low marginal cost periods and the net metering provision provides a capacity payment in the base rates. The UNSE proposal has several advantages that should be noted with respect to introducing the demand charge to the limited group of DG customers. First, customers who install DG are likely to be more sophisticated and more knowledgeable about energy decisions than the typical customer and thus will likely require far less customer education. Second, the move toward more equitable rates begins with addressing the cost recovery for partial requirements customers to eliminate the undue discrimination inherent in the volumetric rates. Third, the UNSE proposal provides a basis for assessing the potential demand response of both DG customers as it relates to solar PV and capacity value and price response to demand based rates.

V. <u>CUSTOMER RESPONSE TO MORE COMPLEX PRICE SIGNALS</u>

Q. IS IT REASONABLE THAT CUSTOMERS CAN AND WILL RESPOND TO MORE COMPLEX PRICE SIGNALS.

A. Yes. In terms of complex price signals the proposals in this case are comparable to rates in other parts of the world. For many years electric utilities have had more complex rate schedules for customers. The first marginal cost based TOU rates were introduced for large customers in the 1950s. It is common to see separate supply and delivery charges with supply charges consisting of multiple blocks or TOU periods. Some rates have a customer charge that is tied to the maximum capacity that can be served by the utility. Under this arrangement the maximum delivery capacity is limited. This is a rate equivalent to a customer charge and a demand rate. In Italy, residential demand rates have been used for many years. Italy is an example of a demand charge that is based on maximum delivery capacity.

Australia is addressing the issue of residential demand charges to address both the issue of cost recovery for solar DG and added loads from air-conditioning in the residential class. The important point is that there is broad recognition of demand charges as a means to fairly recover distribution related costs based on maximum customer demand whenever it occurs. Production and transmission demand charges are partially related to system peak hours as discussed above.

Q. IS THERE EVIDENCE THAT RESIDENTIAL CUSTOMERS CAN RESPOND TO MANDATORY DEMAND CHARGES?

A. Yes. In 2009 a rural electric cooperative in Kansas introduced a mandatory demand charge for recovery of fixed power supply costs based on the peak demand period used by the supplier. The customers of Butler REC have responded as evidenced by the two documents provided in Exhibit HEO- 5. Those documents demonstrate both the educational material and the savings that have resulted from the mandatory rate for residential customers. This shows that the concern of various parties related to the use of demand charges is actually misplaced.

Q. IS THERE EMPIRICAL EVIDENCE THAT CUSTOMERS DO NOT RESPOND TO MARGINAL PRICE SIGNALS AS MUCH AS TO THE TOTAL BILL?

A. Yes. In a 2012 paper by Koichiro Ito of Stanford University[14] found that customers respond to the total bill rather than marginal energy prices. This means that the non-linear energy prices under the inverted block rates are **not** useful as a tool to promote energy conservation. This is further evidence that the insistence of RUCO and others related to the third tier of the inverted rates does not promote conservation and the introduction of more efficient demand rates will not only promote just and reasonable rates, eliminate undue discrimination but will also be consistent with conservation. The findings in this article are not new and have been replicated over the years in various studies. This is further evidence that there is no requirement that residential customers fully understand the components of the rates to promote sound decisions related to a more complex rate design.

VI. CUSTOMER COST ANALYSIS

Q. DO YOU HAVE COMMENTS ON THE VARIOUS WITNESSES WHO RECOMMEND THE BASIC CUSTOMER METHOD FOR CALCULATING CUSTOMER COSTS?

A. Yes. Witnesses for WRA and SWEEP both support the concept of the Basic Customer Method for determining the customer charge. The basic customer method is not a method for calculating the customer component of costs that is based on cost causation because it fails to reflect any costs more than meter, service and direct customer

[14]Do Consumers Respond to Marginal or Average Price? Evidence from Nonlinear Electricity Pricing, October 2012 http://www.nber.org/papers/w18533.pdf

accounting costs such as meter reading and billing in the customer costs and hence the customer charge. It is simply a result driven methodology (lower costs for the residential class and for smaller customers in the class) that does not meet the criteria of theoretically sound cost causation. As a result of this method, all of the remaining distribution system costs must be classified as demand. This includes USOA accounts 364-368. By failing to classify accounts 364-368 as both customer and demand, the resulting cost analysis suffers from significant defects related to cost causation. First, residential customers are allocated a disproportionate share of scale economies in the distribution system. Residential transformers in account 368 have substantially higher costs per kVa of installed capacity than larger demand customers, typically more than twice the cost per kVa. Demand allocation alone assumes the same cost per kVa for all classes. Second, the use of demand to allocate costs for investments in accounts 364 through 367 over allocates the quantity of these inputs to larger customers and assumes that miles of conductor is proportional to demand and not to number of customers. This is empirically an incorrect assumption. Third, public utility regulatory accounting including the NARUC Electric Utility Cost Allocation Manual supports the classification of distribution plant between customer and demand. Based on these factors the Basic Customer Method should never be considered as a viable alternative for calculating the customer charge.

This recommendation appears designed less to follow accepted principles of cost of service analysis and more tailored to advance the interest in artificially depressing fixed charges in rates in order to support higher kWh charges. The economics of solar DG and energy efficiency are both significantly related to the total kWh charge for customers. Increasing the kWh charge provides a larger subsidy for solar customers and is used as a marketing point by the solar industry. It results in a mismatch of customer savings and utility savings when EE investments are made. This is essentially a subsidy for energy efficiency.

Q. IS IT CORRECT THAT THE ONLY COSTS A UTILITY INCURS TO SERVE A NEW CUSTOMER ARE THE METER, SERVICE AND BILLING COSTS?

A. For this statement to be correct, the service line would need to be directly connected to the generator. In the early days of electric service that was the case and generators operated at the same DC voltage as the loads they served. Essentially, the electric utilities served customers in the immediate vicinity and service was unmetered. It was typical to speak of the transmission of electricity from the plant to the customer over a copper conductor and the service area was effectively about 1.5 miles from the generator. If we return to that description of the industry, the statement would be correct except for of course no meter was used. Since none of these circumstances still exist, the statement is incorrect because even to be able to access service requires a transformer and conductor for underground service and poles, conductor and transformer for overhead service.

To see how biased this recommendation is relative to actual costs it is worth noting that the advocates of the Basic Customer Method do not even include all of the labor costs associated with meter reading, billing and customer service. This is true in spite of the accounting requirement to count pensions and benefits applicable to payroll costs in the current period. Further, the method does not account for any office space or equipment necessary to perform the functions deemed to be customer related. As a practical matter, the Basic Customer Method has no support from cost accounting theory for public utilities, the NARUC Electric Cost Allocation Manual or economic theory. Importantly, efficient rates require a customer charge that recovers most if not all of the fully loaded customer costs. Recognition that the costs of the facilities in accounts 364-368 is a necessary condition to have rates reflect cost causation. The minimum system classification properly recognizes cost causation and appropriately shares the benefits of economies of scale among the rate classes. The basic customer charge method requires that all distribution plant accounts be allocated on NCP demand. The result is an under allocation of costs to residential and small commercial customers and excess allocation to larger customers.

Q. WHY IS IT IMPORTANT TO INCREASE THE CUSTOMER CHARGE AS PROPOSED IN THIS CASE?

A. By coupling the higher customer charge with elimination of the third tier as proposed, the intraclass subsidy will be reduced. That is important for moving to rates that meet the cost causation and matching principles. In a market where customers have competitive choices hidden subsidies in even monopoly rates are not sustainable. By improving the rate design gradually, the transition to economically efficient, state of the art, multi-part rates will ultimately be accomplished with fewer and smaller customer impacts.

VII. THE CONCEPTS OF FAIRNESS, EFFICIENCY AND GRADUALISM

Q. ARE THERE GENERALLY ACCEPTED PRINCIPLES OF RATE DESIGN THAT PLAY A ROLE IN THE RATE PROPOSALS OF THE PARTIES?

A. There are always important principles that should be reflected in rate design. The three principles of fairness, efficiency and gradualism have been recognized by a number of the witnesses in their testimony either directly or indirectly. These principles are consistent with rate principles developed by Bonbright and discussed widely by others. The following is a summary of the witnesses' views:

TASC witness Fulmer concludes that "As I discuss throughout this testimony, UNSE's proposal to double the monthly customer charge and require new DG customers to be on a three-part rates violates the principles of understandability, public acceptability, avoidance of undue discrimination, and wastefulness." I will discuss this concept below.

APS witness Faruqui cites Bonbright a number of times in his testimony. He summarizes the principles and discusses their applicability in detail. While I agree with much of that discussion there are issues that make his recommendation inconsistent with cost causation.

SWEEP witness Schlegel uses Bonbright as support for his basic customer charge argument and states "The definition and composition of a customer fixed charge should be consistent with the definition contained in Bonbright's Principals of Utility Rates. Bonbright defines basic customer costs as those operating and capital costs found to vary with the number of customers regardless, or almost regardless, of power consumption." I will show below that the UNSE proposal is completely consistent with Bonbright and that witness Schlegel has reached an erroneous economic conclusion.

Q. PLEASE DEFINE THESE THREE PRINCIPLES.

A. In defining gradualism as a measure of rate change for individual rate components such as customer charges, the witnesses for the other parties seem to focus solely on a percentage increase as the measure of gradualism. Looking solely at percentage increases as the basis of determining gradualism can often give very misleading results. Thus the TASC concern for a 100% increase in the customer charge as violating gradualism is misplaced. Both Staff witnesses recommend gradualism but provide no precise definition of the concept. They use it to temper class increases and rate design and one can only infer from their recommendations what their view may be. Similarly the AECC endorses gradualism in both cost allocation and rate design. To properly define gradualism it is necessary to recognize that gradualism is not based solely on a percentage increase basis. For example, if one were to make a rate proposal introducing a new billing determinant, such as a demand charge, with a charge of one cent, the percentage increase would be infinite but would hardly violate the principle of gradualism. The same is true in this case where the percentage increase of 100 percent in the customer charge translates to an approximately $0.33 per day increase in the customer charge. The current charge is relatively low compared to both the cost of service and the level required for economically efficient two-part rates. A $0.33 per day increase is fully consistent with the principle of gradualism. Fundamentally, there is an increase in fixed costs occurring; some increase in fixed charges is justified. Another example applicable in this case is assessing the actual bill differences for customers from the prior period including the impact of the reduced Base Power value. This provides addition head room for adjusting rates without violating the gradualism principle.

In this case, there is no adverse impact on the kWh price signal from the increased customer charge as that increase does not recover all of the increase in residential revenue requirement. Failure to increase the customer charge violates principles of fairness by increasing undue discrimination. Every witness in this case agrees that changes in distribution costs are driven by changes in the number of customers and NCP demand or NCP alone, not by kWh consumption. Simply, it is insufficient to define the principle of gradualism solely along a percentage increase as even a de minimis actual increase may be a significant percentage increase for a low dollar rate impact. Actual increases must also be assessed in real (as opposed to nominal) bill increases.

Q. PLEASE DEFINE THE CONCEPT OF FAIRNESS.

A. This is the most difficult of the three concepts to define since fairness is often in the eye of the beholder. As a case in point, solar DG advocates see nothing unfair about DG customers paying hundreds of dollars less for delivery service than full requirements customers pay for exactly the same service. They also see nothing wrong with using a high cost kWh in the summer and swapping it out with a low cost kWh in the spring or fall even though other customers must make up that shortfall in fuel costs. Finally, they see nothing wrong with net metering that allows them to save the full Base Power plus PPFAC even though the avoided energy costs (the solar actual savings) is always less than the Base Power plus PPFAC and other customers must pay the difference. From their view this is fair. When Bonbright defined fairness (or equity as used by APS witness Faruqui) it is explicitly defined in terms of cost allocation based on cost causation. As a general rule both customers and the courts have a view that fairness results when rates reflect the principles of cost causation and the matching provision that the charges for customers match the costs incurred as the service is provided. It is certainly not correct that differences in rates that reach the level of undue discrimination are fair as defined by Bonbright himself who specifically notes that rates must not be unduly discriminatory.

Q. PLEASE DEFINE THE CONCEPT OF EFFICIENCY.

A. The concept of efficiency has both a demand and supply dimension. In either event efficiency requires that prices be set on marginal cost. The key point is that when a customer purchases an additional kWh or requires more delivery capacity (kW) the charge should reflect the cost of that additional service. KWh charges cannot be efficient for purchases of capacity and the current Base Power plus PPFAC charge cannot be efficient when costs vary both seasonally and diurnally. The recovery of costs in demand charges cannot be efficient with a single demand charge because a single charge cannot simultaneously reflect coincident peak load characteristics and non-coincident peak load characteristics. If the signals do not match cost causation the incorrect incentives will result in even more costs for customers and larger potential subsidies from inefficient investments. As a case in point, charging too much for peak demand will promote investment in storage to reduce peak demand but will not save the utility costs beyond the generation capacity component. Other customers will be forced to pay more as the result of excess storage investment. Further, the customers hardest hit by these types of cross subsidy are those who cannot afford solar DG, do not have an economic location for storage, do not own their premise and those who cannot afford storage investments.

Q. WHY ARE THESE THREE PRINCIPLES IMPORTANT IN RATE DESIGN IN PARTICULAR?

A. While all of the Bonbright principles are important and in fact some are even mandated by the courts, these three principles apply specifically to rate design and support principles that are also related to other aspects of regulation such as revenue requirements or environmental efficiency by internalizing externalities that have been included in utility costs. These three principles are most important for rates because they provide significant guidance in the design of particular rate elements. For example the witness for SWEEP says that the Bonbright principles support the use of the basic customer charge. He notes that "Bonbright defines basic customer costs as those operating and capital costs found to vary with the number of customers regardless, or almost regardless, of power consumption." If we turn to utility cost accounting, the NARUC Electric Cost Allocation Manual (NARUC Manual) or economic analysis, we find that Bonbright's definition means far more than basic customer costs defined by the SWEEP witness.

As Dr. James Suelflow writes in his treatise Public Utility Accounting: Theory and Practice published by the Institute of Public Utilities at Michigan State University: "... distribution transformers and primary and secondary lines including conductors and devices (account 365 "Distribution Plant") and poles and towers (account 364 "Distribution"), all contain capacity and customer costs." Dr. Suelflow recognizes that costs are more closely related to customers the closer one approaches the ultimate customer. In other words, assets that are in closer proximity to the load served reflect less diversity and the classification of the costs associated with those assets should recognize this point and those costs do not vary with power consumption.

The correlation between customers and a portion of distribution costs has been confirmed by academic and regulatory research work related to estimating Total Factor Productivity (TFP) for use in price cap regulation where customers or connections has been an output measure for calculating the X-Factor in the formula P = I – X. The formula P= I – X is essentially a formula that relates either price or the functional equivalent revenue requirements to inflation and changes in productivity as measures by the relationship of physical outputs like customers and demand to measures of physical inputs such as meters or transformers. For example, the following statement from an Australian electric distribution TFP study says "The connection component recognises that some distribution outputs are related to the very existence of customers rather than either throughput or system line capacity. This will include customer service functions such as call centres and, more importantly, **connection related capacity (eg having more residential customers requires more small transformers and poles)**." (Emphasis added.) This information is developed specifically for a network electric utility providing delivery services. I would note that the emphasis on connections as related to connection related capacity is the result of the correlation of distribution costs to the number of customers. In a more recent study related to the electric distribution utilities in Ontario, Canada, The Pacific Economics Group (PEG) found that customer numbers was an empirically significant output measure for determining productivity. In each case the productivity measure is used to determine the expected changes in costs over time. As an aside, the customer component of TFP has the largest cost elasticity weight meaning the customer component is more significant than the other output measures. In addition to Australia and Ontario, other jurisdictions such as Great Britain and the Netherlands also use customer numbers to develop TFP.

Based on this research, it is fair to conclude that the weight of modern empirical evidence is fully supportive of the minimum system use to classify a portion of the distribution system costs in accounts 364-368 as both customer and demand. The customer component of these costs is wholly consistent with the Bonbright definition of costs measured as those that do not vary with power consumption.

Finally, there is no question that the NARUC Manual states that the distribution plant costs in Accounts 364-368 have both a demand and a customer component. The NARUC Manual states "When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer- related costs." (Emphasis added.) NARUC's position is unequivocal in this regard. It specifically provides only two alternatives for the classification and allocation of more than basic costs to the customer component. Thus SWEEP witness Schlegel's own definition of customer costs supports, consistent with the Bonbright authority he relies on, results in a much larger customer charge including a fully loaded portion of the distribution system as part of an efficient and fair customer charge. The concept of a basic customer charge is not supported by Bonbright, cost accounting, empirical evidence from economic theory or even NARUC.

Q. YOU NOTED ABOVE THAT YOU WERE IN GENERAL AGREEMENT WITH APS WITNESS FARUQUI ON APPLICATION OF THESE PRINCIPLES. WHERE DO YOU DISAGREE?

A. My disagreement is not theoretical but rather based on the principles of cost causation noted above and a fundamental difference related to distribution demand costs. As I have shown above the proper customer charge is more than basic customer costs thus Dr. Faruqui has not recommended a customer charge consistent with cost causation. He has also recommended a demand charge concept as follows: "It is typically applied to the individual customer's maximum demand, either during a defined on-peak period, or regardless of time of occurrence, or based on a combination of the two." At a minimum there must be two separate demand charges, one would be the distribution costs in a facilities charge based on maximum demand whenever it occurs and another demand charge for production and transmission costs based on a demand measured in a peak period. If by a combination of the two, Dr. Faruqui means a separate facilities demand charge such as used by Empire District Electric in their general service demand rates than there is no disagreement. This point should be clarified.

VIII. <u>SERVING ALL CUSTOMERS IN A CLASS UNDER THE SAME RATE SCHEDULE</u>

Q. WHY IS IT IMPORTANT TO SERVE ALL CUSTOMERS IN A HOMOGENEOUS RATE CLASS UNDER THE SAME RATES?

A. All customers with like service characteristics have the same cost causing factors and should be subject to the same price signals regardless of other circumstances that may warrant different treatment from a societal perspective. Using the same rate sends the same price signals so that even customers who may require special consideration see the same incentives for efficiency as all other customers. The question becomes how to provide utility bill assistance to customers whose circumstances warrant special consideration.

Q. HOW HAVE UTILITIES ADDRESSED THE ISSUES OF SPECIAL NEEDS CUSTOMERS?

A. Utilities have used a variety of options to address low income consumers and others with special needs. In fact, the inverted block rates used in California and adopted elsewhere including Arizona were instituted as lifeline rates in the 1980s based on the idea that low income customers were low users and that low customer charges coupled with a suitable low tier would provide assistance to low income customers. As a practical matter the assumption of correlation between use and income is weak at best and actually non-existent in many cases.

Beyond tiered rates utilities have used several basic methods to address low income issues: discounted charges; fixed dollar discount; fixed percentage discount; means tested discounts; age tested discounts; percent of income plans and so forth. Each of these general concepts has variations as well. For example, means tested discounts may be a percentage of the bill, a percentage of the bill excluding fuel costs, a dollar amount and so forth. The one element that all have in common is they provide assistance to some subset of residential customers deemed to require bill assistance.

From an economic perspective these tools are typically not designed to maximize the benefits of assistance. Rather they are a crude method for providing assistance unrelated to the actual need of the customer. The need for assistance is a function of income, family size, household age distribution and a variety of variables that impact the customer's bill. For example, the increased customer charge benefits all low income customers whose use exceeds the system average on an annual basis. Thus the argument against increasing the fixed charge and reducing the intraclass subsidy works against those who have the largest bills. Decreasing the intraclass subsidy provides more relief for those who have the highest impact whether the relief is fixed dollar amount or a percent of the bill. It is not uncommon for this to benefit more than half the low income customers. Even under a means tested discount it is possible that the higher customer charge would result in a more favorable outcome for larger customers. Under a percentage of income plans the rate design has no impact on a qualifying customer. Finally, the ACAA paints a picture that increasing the customer charge will have dire consequences for low income customers without providing any empirical evidence of any such impacts. Given the saturation of electric appliances from the Residential Energy Consumption Survey for 2009 (the latest year available) it is unlikely that any significant number of low income customers who pay their own bills and are not poor (college students for example) have annual consumption that is as low as 300 kWh per month. These low uses tend to result from other impacts such as partial month bills or use during months with no heating or air-conditioning load.

This conclusion is supported by the bill frequency data provided in response to a data request to UNSE. I have summarized that frequency data in Exhibit HEO- 6. The exhibit shows that only 17.5% of CARES customers have monthly bills below 300 kWh as compared to 22.5% for non-CARES customers. That same exhibit shows that the kWh frequency for CARES customers is virtually the same as for the class as a whole at all cumulative consumption levels. This is not surprising when one considers that the average bill for CARES customers is 769 kWhs per month and for all customers is 830 kWhs or only 61 kWhs per month more than CARES. As a practical matter it is also important to understand the data in the bill frequency includes bills for less than thirty days as the result of turn-offs and turn-ons. The frequency of low income moves is typically higher than for the population as a whole with some exceptions such as college communities.

ACAA also claims that the "most frequent bill" for CARES customers shows usage in the 400 kWh range, their own data (Figure 2) contradicts this finding; in that figure, the largest number of bills issued to CARES customers is in the 1,500 kWh range – the same range that is shown in Figure 1 for RES-01 customers as having the highest number of bills.

Q. WILL THE THREE PART RATE ADVERSELY IMPACT LOW INCOME CUSTOMERS?

A. As with most questions about impacts the response is it depends. If the customers have a high peak demand and low annual use bills will increase. On the other hand if these customers use mostly baseload service with low coincident peak and non-coincident peak demands the three part rate will also provide a benefit for these customers as a result of lower energy charges and higher load factors. Further, the three part rate will help low income energy programs focus on efficiency measures that will not just save kWhs but will also reduce demand.

IX. CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. I conclude that the size and nature of the solar subsidy is significant and that the net metering banking provision contributes directly to this subsidy based on avoided energy costs and avoided fixed costs. As proposed by UNSE that provision should be eliminated at least going forward and I would suggest that it be eliminated for all customers as soon as practical. Second, I agree with Staff that a multi-part, unbundled rate is the solution to addressing cost recovery for all customers. Until such time as that rate is fully implemented for all customers, solar DG customers should be served under a separate rate schedule that fully embodies the principles I have discussed above as a multi-part rate that includes customer charges, demand charges and TOU energy charges all based on cost causation. Third, I conclude that serving all full requirements residential customers including CARES customers under the same rate is appropriate as both UNSE and the Staff have noted. I agree that increasing the customer charge substantially is required for more efficient rates. Finally, I agree that the third tier of the inverted rate should be eliminated and that no tiers are required under multi-part rates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Appendix A

DR. H. EDWIN OVERCAST

Educational Background and Professional Experience

Dr. Overcast graduated cum laude from King College with a Bachelor of Arts Degree in Economics. He received the Doctor of Philosophy Degree in Economics from Virginia Polytechnic Institute and State University. His principal fields of study included Economic Theory, Public Finance and Industrial Organization, with supporting fields of study in Econometrics and Statistics. He has taught courses at both the graduate and undergraduate level in Microeconomic Theory, Managerial Economics and Public Finance. In addition, he has taught courses in Mathematical Economics, Economics of Regulation and Money and Banking. While a faculty member at East Tennessee State University, he was appointed to the Graduate Faculty and subsequently directed thesis programs for graduate students.

In 1975, he joined the Tennessee Valley Authority (TVA) as an Economist in the Distributor Marketing Branch. He held successively higher positions as an Economist in the Rate Research Section of the Rate Branch and was ultimately Supervisor of the Economic Staff of the Rate Branch.

In May of 1978, he joined Northeast Utilities as a Rate Economist in the Rate Research Department and was promoted to Manager of Rate Research in November 1979. In that position, he was responsible for the rate activities of each of the operating companies of Northeast Utilities: Western Massachusetts Electric Company, Holyoke

Water Power Company, Holyoke Power and Electric Company, The Connecticut Light and Power Company, and the Hartford Electric Light Company.

In March 1983, Dr. Overcast became Director of the Rates and Load Research Department of the Consumer Economics Division of Northeast Utilities. In this position, Dr. Overcast directed the planning of analyses and implementation of system-wide pricing and costs for regulated and unregulated products and services of Northeast Utilities. As part of that responsibility, Dr. Overcast represented the system companies before state and federal regulators, legislative bodies and other public and private forums on matters pertaining to rate and cost-of-service issues.

Dr. Overcast represented Northeast Utilities as a member of the Edison Electric Institute (E.E.I.) Rate Committee and the American Gas Association (A.G.A.) Rate Committee. While serving on those committees, he was the Rate Training Subcommittee Chairman of the A.G.A. Rate Committee. He has been an instructor on cost-of-service and federal regulatory issues for the E.E.I. Rate Fundamentals Course and the E.E.I. Advanced Rate Course. Dr. Overcast also represented Northeast Utilities as a member of the Load Research Committee of the Association of Edison Illuminating Companies.

In March 1989, he joined Atlanta Gas Light Company as Director - Rates and was promoted to Vice President - Rates in February 1994. In November 1994 he became Vice President - Corporate Planning and Rates and was subsequently elected Vice President - Strategy, Planning and Business Development for AGL Resources, Inc., the parent company of Atlanta Gas Light Company. His responsibilities in the various rate positions included: designing an administering the Company's tariffs, including rates, rules and regulations and terms of service. He represented the Company before regulatory commissions on rate and regulatory matters and oversaw the preparation of the Company's forecast of natural gas demand. He was responsible for planning activities relating to the regulated businesses of the Company. He developed strategy for both regulated and unregulated business units, monitored markets for new products and services and identified potential new business opportunities for the Company.

Dr. Overcast has previously testified in rate cases and other proceedings before the Connecticut Department of Public Utility Control, the Massachusetts Department of Public Utilities, the Georgia Public Service Commission, the Montana Public Service Commission, the Missouri Public Service Commission, the Kansas Corporation Commission, the Arkansas Public Service Commission, the Corporation Commission of Oklahoma, the Ohio Public Utilities Commission, the New York Public Service Commission, the New Jersey Board of Public Utilities,. the Michigan Public Service Commission, the Public Service Commission of Maryland and the Tennessee Regulatory Authority and the Federal Energy Regulatory Commission. In Canada, he has testified before the Ontario Energy Board, the British Columbia Utilities Commission, the New Brunswick Energy and Utilities Board and the Alberta Energy and Utilities Board. He has also testified before the subcommittee on Energy and Power of the U.S. House of Representatives and various committees of the Georgia General

Assembly.

Dr. Overcast joined R. J. Rudden Associates, Inc. as Vice President in September 1999. R. J. Rudden Associates became a unit of Black and Veatch in January of 2005. At that time he became a Principal of the EMS Division, he is currently a Director in the Management Consulting of Black and Veatch.

Appendix B

SMART RATES FOR SMART UTILITIES

Creating a New Customer Paradigm with Enhanced Pricing of Utility Services

H. Edwin Overcast

BLACK & VEATCH
Building a world of difference.

Table of Contents

Introduction

The U.S. electric utility industry is in the midst of rapid technological change and a transformation of the customer service paradigm. Much of the debate surrounding the changing industry centers on the implementation of more sustainable practices, such as energy efficiency and distributed energy resources, and compliance with more stringent environmental regulations. Notably, the debates continue to focus on technological and operational solutions. However, developing a 21st century rate design, or Smart Rates, can help facilitate solutions to today's industry challenges and provide customers with better price signals to assess competitive service offerings.

Smart Rates recognize that utilities provide a variety of services to customers and that the costs of these services are not always caused by the amount of energy the customer consumes. From a rate design perspective, Smart Rates fully unbundle[1] each component of utility costs and bill those components on the appropriate customer billing determinants consistent with the concept of cost causation. The unbundling of costs changes virtually all of the current rate traditions because it no longer rolls all utility costs into a single kilowatt-hour (kWh) charge or single kilowatt (kW) charge as if those costs are caused only by the single measure of customer energy consumption. Cost unbundling is critical for accommodating competition from on-site generation and allowing customers to choose which services they need from the utility.

This paper sets forth the theory and practice of 21st century rate designs through full rate unbundling of utility services and provides a framework for "Smart Rates" that enable customers to purchase – and pay an equitable and supportable price for – the services they want and need, regardless of their energy consumption levels. Through the use of Smart Rates, a utility can send customers a proper price signal associated with each service and improve the efficiency of all its services to customers.

Many aspects of the electric utility industry have changed dramatically since its founding, yet rate structures have significantly lagged these advancements. In order to best represent today's electric services and meet the needs of today's electric consumers, modern rate designs are essential. Smart Rates enable customers to use electricity and electric services more efficiently and provide utilities with revenue stability that enable the offering of more responsive services to accommodate customers' specific demands.

[1] Rate unbundling in this context is simply pricing each utility provided service separately so that customers pay only for the services they use, rather than paying a single charge that includes all services and assumes that all customers within a class have homogenous service requirements.

The Challenge with Current Utility Rate Designs

Current utility rate designs have their foundation in rates developed in the 19th century. The most common rates in use today are based on the watt-hour meter and consist of a fixed customer charge and some form of volumetric charge per kWh. As a practical matter, the choice of rate designs for various customer classes has depended specifically on the cost of metering relative to the total cost of service to the customer. For larger customers, most utilities use one of the following rate forms, both developed in the 19th century, or a combination of the two forms:

- **Hopkinson Demand Rate:** The most common method of pricing electricity for customers served with demand meters, such as large industrial customers. The Hopkinson Demand Rate consists of an energy charge for total kWh consumption in addition to a demand charge based on the facility's maximum energy use during any short time period (quarter-hour, half-hour or one-hour) in the month.
- **Wright Hours Use of Demand:** This rate form is also used for demand metered customers and bills those customers using kWh charges for different levels of hours use of demand. The Wright Hours Use of Demand consists of a customer charge and kWh charge blocks based on the number of hours that the customer's maximum monthly demand is used. Hours use is calculated by dividing the monthly kWhs by the measured maximum demand. The price of energy declines as the hours use increases recognizing both the customer's increased load factor and the increasing use of off-peak energy.

Even today, not all electric service applications are metered and the rate design used for such services are the same flat rate service used by the industry when it first started delivering electric power to customers in the 1880s.

Unless the rate design reflects cost causation for the services provided, customers who elect to buy particular service components will not pay for all the services they consume. This creates market instabilities as the result of cross-subsidies embedded in the utility's rates. Such cross-subsidies cannot withstand today's market pressures and will result in skewed prices and service levels for all market participants.

UNDERSTANDING COST DRIVERS

As noted, modern regulatory requirements for demand-side management (DSM) and energy efficiency, as well as customer demands for distributed generation (DG), do not align with current utility rate structures. The reason for this is that current rate structures incorrectly assume that energy, or measured kWh use, causes the utility to incur nearly all costs except for the costs that are reflected in a modest customer charge. For larger customers, the use of both a demand component and an energy component assume that a single measure of kW demand coupled with a unit kWh charge cause all of the fixed costs of utility service. In reality, utility services and the costs associated with each are caused by fixed and variable cost drivers. Both the fixed and variable cost drivers differ for different cost components and for different seasonal and diurnal periods.

Fixed costs do not change with energy use but can vary as a result of other cost drivers, such as customers or demand. Because these costs are fixed, they do not change with any hourly pattern of energy use, even though some time interval is used to measure demand (e.g., highest 15, 30 or 60 minutes). *Appendix A* provides a brief description of the determination of demand for billing capacity-related costs to customers. Examples of utility fixed costs include:

- The investment in the fleet of plants generating electric power.
- The integrated transmission network investment that moves power from generators to the distribution system.
- The distribution system that provides power to homes and businesses.

Variable costs, on the other hand, can vary by season of the year, time of use, and/or environmental conditions such as forced outages or partial unit deratings that change the marginal source of energy for a particular time period. Examples of variable costs include:

- Fuel and fuel handling costs.
- Purchased power.
- Volumetric charges from regional transmission organizations (RTOs) or independent system operators (ISOs).
- Chemical costs.
- Energy-related operations and maintenance costs.
- Other environmental costs.

A Utility's Cost Causative Factors

Whether fixed or variable, costs are generally caused by one or a combination of three general factors:

- **Customer:** In general, if a cost varies as a result of customer count, then this is a customer-caused cost and can include customer service expenses (e.g., billing and meter reading), and facilities or assets located on the customer premise, such as the meter and service line, and even portions of the distribution system that serve to connect customers to the grid.
- **Energy:** These are the costs that vary directly with the number of kWhs produced, with the cost of fuel being the largest component.
- **Demand**: Demand related costs are those costs caused by the largest load in kW imposed on various parts of the utility's transmission or distribution systems.

  NOTE: *The demand factor that causes costs differs for different types of cost elements. For example, some form of coincident demand is the cause of both utility production and transmission costs. This peak hour or other measure of demand drives the required capacity along with a level of reserves and it is this measure of demand that should be the basis for the charges to recover that unbundled cost.*

Understanding the nature of different utility costs, the types of costs, and what causes costs to be incurred enables utilities to use specific pricing mechanisms that align with cost factors (Table 1).

Table 1 - Unbundled Costs by Type and Causal Factors

COST FUNCTION	COST TYPE	CAUSAL FACTOR(S)	PRICING
Generation Plant	Fixed	Demand	kW Charge
Transmission Plant	Fixed	Demand	kW Charge
Distribution Plant	Fixed	Demand, Customers	kW Charge and Customer Charge
General Plant	Fixed	Demand, Customers	kW Charge and Customer Charge
Generation O&M	Fixed, Variable	Demand, Energy	kW Charge and kWh Charge
Transmission O&M	Fixed	Demand	kW Charge
Distribution O&M	Fixed	Demand, Customers	kW Charge and Customer Charge
Administrative & General costs	Fixed	Demand, Customers	kW Charge and Customer Charge

This table shows the appropriate type of charge to recover the categorized costs in order to match cost causation with pricing without a detailed specification of the particular charge.

UNDERSTANDING UTILITY SERVICES

Unbundling of rates requires an understanding of all services a utility provides, and the cost drivers for each service. Most stakeholders generally understand that a utility provides safe and reliable electric service to its customers. However, most characterize this service as simply providing the energy product, which is one reason why the kWh-based rate structure continues to prevail today. In reality, utilities provide numerous services, including:

- Generation service
- Transmission and distribution services
- Customer service
- A variety of services that provide safe and reliable operation of the electric system as well as the facilities that use the electricity behind the meter, such as voltage regulation, in-rush current for starting electric motors and other ancillary services.

Each of the listed major functions of the utility can provide multiple specific services for a variety of customers. Furthermore, each service also includes a quality of service component, generally defined as firm or non-firm. Firm quality means that the utility provides service continuously without interruption except those related to unavoidable system outages (e.g. outages caused by severe weather). Non-firm quality means that the customer has agreed with the utility to permit its service to be interrupted at times the utility chooses. Table 2 demonstrates the multiple services provided under the generation functional umbrella, and how those services have different patterns of cost based on the quality of service.

Table 2. Potential generation services

SERVICE	QUALITY
Full Requirements	Firm
Full Requirements	Non-Firm
Partial Requirements- Supplemental	Firm/ Non-Firm
Partial Requirements- Supplemental Baseload	Firm/ Non-Firm
Partial Requirements- Supplemental Peaking	Firm/ Non-Firm
Partial Requirements- Standby/Backup	Firm/ Non-Firm
Partial Requirements- Maintenance Service	Firm/ Non-Firm
Partial Requirements- Scheduled Maintenance Service	Firm/ Non-Firm
Partial Requirements- Unscheduled Maintenance Service	Firm/ Non-Firm
System Related Services- Black Start, Area Protection, Frequency, Transmission Support	Firm

As Table 2 illustrates, there are many potential services (the list is not intended to be comprehensive) provided by the generation assets. Each service has different cost characteristics as well as quality differences. The result is that rates for unbundled generation may differ based on the type of service required. A similar set of requirements relate to transmission and even to some distribution services, although the closer the service is to the customer the less costs and quality of service provided vary. For example, if the provision of energy is non-firm, that service does not change the cost of the distribution facilities for serving the customer because the utility must still be able to meet the customer's maximum requirements when there is no interruption of service.

MODERN CHALLENGES TO TRADITIONAL RATES

Net Metering Policies

The fallacy of applying 19th century rate structures to the types of 21st century electric utility services required by customers is made clear by the economic effects of DSM programs, and the growing adoption of DG assets (e.g., rooftop solar) among customers who seek the economic benefit net metering policies provide. While these customers are using less energy, and some may even be net-producers of energy, they are still using utility services. However, because current rate structures assume that the level of kWh consumed by the customer causes the utility's costs; discontinuities in billing and cost recovery among customers are created. According to the Edison Electric Institute (EEI):

While net metering policies vary by state, customers with rooftop solar or other distributed generation systems usually are credited at the full retail electricity rate for any electricity they sell to electric companies via the grid. The full retail electricity rate includes, not only the cost of power but also all of the fixed costs ... that makes the electric grid safe, reliable, and able to accommodate solar panels or other distributed generation systems. Through the credit, net-metered customers effectively are avoiding paying these costs for the grid.[2]

Net metering is the practice of allowing on-site generation to reduce the kWh portion of the residential customer's bill (netting generation against load) on a unit kWh generated basis. Recognizing that under a utility's traditional rate design the kWh charge for these customers recovers most of the fixed costs and the variable costs of energy on an average basis, the compensation for the customer's level of self-generation essentially assumes that all of the costs not recovered under net metering can be saved by the utility. That is simply not the case.

Consider, for example, the utility that peaks after sunset in every month of the year. Solar PV makes zero contribution to reducing the fixed costs for that utility. Importantly, the only cost savings are the avoided energy costs - and that would not even be valued at the utility's highest energy cost hours. In this case, net metering forces all non-solar PV customers to bear the costs of production, transmission and distribution capacity costs that are caused by the solar PV customer. While this is an extreme case to illustrate this deficiency in net metering, there are many utilities where the peak loads occur when solar PV is not generating its maximum output. This means that the avoided costs of the utility will not be as large as the credit provided under net metering, and that a cross subsidy will be created which allows solar PV customers to avoid paying for the fixed costs they cause the utility to incur.

Demand-Side Management Issues

With respect to DSM, issues similar to those under net metering arise when DSM programs save energy, but not capacity. A simple example illustrates this point:

A recreational facility owner invests in skylights to save energy during the day. The skylight salesman calculated his expected savings by dividing the total utility bill by the monthly kWh and providing a unit kWh savings. However, the facility was billed on a commercial rate that included a demand charge. Needless to say, the savings did not materialize because the facility's peak demand occurred at night due to its heavy lighting load. The skylights created no demand savings - only daytime energy savings. Based on the actual savings, the skylights were not economic and the owner made a poor decision to invest his limited capital on an inefficient solution to reduce energy-related costs.

By unbundling rates, the utility recovers all of its costs from each customer regardless of the amount of energy (kWh) used by the customer, or when the energy was used. Such a pricing structure will create rates that fairly portray the value of the service in the market and will eliminate the inherent

[2] "Straight Talk About Net Metering." Edison Electric Institute (http://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/Straight%20Talk%20About%20Net%20Metering.pdf). September 2013.

intra-class cost subsidies in current utility rates, creating benefits for all segments of the energy industry.

21st Century Rate Design

A 21st century rate design fully unbundles each component of cost and bills those components to customers based on the appropriate billing determinants (customer, kW, kWh) consistent with cost causation. The unbundling of costs and the implementation of modern rate designs appropriately change virtually all of the current rate traditions perpetuated over the years. Different rate components are billed separately and each customer will only pay for the services they use. This section focuses on the components of an unbundled rate design.

Unbundled rates consist of the basic customer, demand and energy charges. Under full unbundling, these basic rate components are translated into:

- Customer charge
- Production demand charge
- Transmission demand charge
- Distribution demand charge
  - Distribution substation service
  - Distribution primary service
  - Secondary distribution demand
- Energy charge
  - Energy service at transmission voltage
  - Energy service at substation delivery
  - Energy service at primary delivery with and without transformation
  - Energy service at secondary voltage.

Obviously, not every utility will require all of these distinct charges based on their existing service arrangements and the customers' available service options. Further, there may well be subcomponents of various costs associated with services such as back-up, standby, maintenance and supplemental power as each relate to generation, transmission, distribution and energy services. In some markets, unbundled services, such as meter reading and billing, may not be provided by the utility. In that case, the customer charge component needs to reflect the exclusion of the costs of these services.

A customer's rates may also differ based on geographic segments of the utility's system because costs may differ at different load nodes (this consideration is particularly important for systems with wide geographic reach that include different load nodes and/or climatic considerations.)

UNBUNDLED RATE COMPONENTS

Derivation of the Customer Charge

The derivation of a fully unbundled rate design begins with the customer cost component. While customer costs will always be a subject of debate among a utility's stakeholders, the logic supporting this concept is quite simple: If a cost varies based on customer count, then the cost is customer-related. This includes a utility's customer service functions and its assets located on the customer premise.

Another element of customer costs are those portions of the utility's minimum distribution system required to serve even the smallest customer. Minimum distribution system requirements include transformers, secondary conductors, poles and/or underground facilities.

To derive its fixed customer charge, a utility uses a detailed cost of service study that unbundles costs into various components. These unbundled costs form the basis for setting the rates for each component of service. For example, if the cost of service study calculates the customer component to be $300 per year, that amount would be the basis for a $25 per month customer charge. The annual cost derived from the utility's cost of service study would include the annualized cost to support the investment in a meter, service line, transformers, secondary conductors and poles, Operation & Maintenance (O&M) expenses related to the customer's plant, general plant, and any other assets required to provide the service, and customer service expenses (e.g., billing, meter reading, customer accounts and collections).

Derivation of the Production Demand Charge

Not all electric utilities will have production demand charges. This discussion focuses on the need for such charges for a vertically integrated utility. In that case, the production demand charge includes the fixed costs of generation and the transmission lines and related facilities that interconnect the utility's generation to its bulk transmission system. Ideally, these costs would be collected through two separate demand charges. This is the preferred rate structure because the typical electric utility experiences distinct differences between the marginal costs of production for serving peak loads compared to the costs for serving loads occurring other than during the peak period (i.e., base load production). At the same time, with the expected increase in the penetration of distributed energy resources (DER) on utility systems, this rate structure will properly value the benefits of DER to the customer based on the times when such self-generation actually is operating.

In general terms, the first demand charge (known as the Production Peak Demand Charge) recognizes the capacity costs associated with the utility's peak demand period, while the second demand charge recognizes the higher capacity costs of base load units that provide substantially lower energy costs. These costs are recovered based on the maximum demand in the peak demand period subject to a one hundred percent ratchet.

The carrying cost of the utility's least-cost production resource (nominally a gas turbine) and the associated transmission costs would be collected as a demand charge based on a demand measure during the highest load hours, where load is defined as: *The sum of customer load, forced outage load, scheduled outage load and generator deratings.*

This demand charge reflects the unbundled costs of required capacity with a level of reserves. The result is that certain charges may be incurred by the customer based on specific time periods that may differ from on-peak hours for energy, in general, and may differ for generation and transmission. For example, if the reserve requirements are calculated by an RTO or ISO based on a specific set of critical hours, those critical hours may be appropriate for determining the billable production demand associated with peaking facilities. If these hours are very short periods, such as the maximum demand hour in the summer months of June, July and August, it is not feasible to know in advance when those peak hours may occur and the peak hours used to measure the hours when the demand charge is applied may change from year-to-year and month-to-month.

It is important to note that deriving the Production Peak Demand Charge based on a short demand period runs the risk of shifting load out of that period. In addition, this also creates risk for increasing load after the peak demand period, causing the peak to occur in different hours because shifting load out of a short period may reduce natural diversity. It is critical that the shifting peak concept be fully assessed because there is a possibility that the loss of natural diversity in loads may cause other capacity-related costs to increase - such as for the utility's distribution and transmission facilities.

By establishing a longer fixed period for deriving the Production Peak Demand Charge, the shifting demand peak creates no issue for creating a new production demand peak outside of the demand hours. This is done by taking advantage of the natural diversity that occurs between loads.

It is also critical to understand that the need for capacity is based on more than just the customer load on the utility's system. Simply, the total maximum load on the system is the sum of customer loads, scheduled outage loads, unscheduled outage loads and unit derating loads. The latter two components change for every time interval just like customer loads. In some cases, the seasonal derating is known in advance based on the generation technology or a condition such as lower water flows that occur naturally.

Other factors may also derate the capacity of a unit without forcing the unit out of service (e.g., tube leaks). Since these types of occurrences reduce available capacity, they must be treated as load for purposes of determining the peak hours that matter for cost causation purposes. It has been said that if load factor on the generation system increases beyond a certain point, it will be necessary to build reserves just to schedule maintenance activities. Thus, it is important to understand the full demand on generation resources for purposes of establishing the demand period for production. Shifting load to off-peak periods does not always result in the full expected savings and could with some technologies create a new peak period in the former off-peak hours.

The second demand charge (known as the Production Base Load Demand Charge) is designed to recover that portion of the utility's revenue requirement associated with production not recovered through the Production Peak Demand Charge. The value of this charge may be zero in some circumstances. Where there are additional costs, the Production Base Load Demand Charge will be based on the highest monthly demand outside the peak demand period, without any ratchet provision. Thus, customers who benefit from lower cost energy will contribute to the additional capacity costs that produce those savings.

In the alternative, where utilities operate in restructured markets, the Production Peak Demand Charge of RTO or ISO participants could be based on the capacity responsibility determined by the operational control entity. This charge would be subject to a 100 percent ratchet on an annual basis. The remainder of the capacity costs not covered by the Production Peak Demand Charge would be recovered in a second demand charge applicable to the highest monthly load occurring in the month, without a ratchet.

Derivation of the Transmission Demand Charge

For transmission, the analysis of peak loads need not be the same as for generation. On integrated utility systems, native load may be only one component of the peak load. Understanding how the system is loaded on an hourly basis is a necessary element for the determination of transmission system peak periods. It is possible that the demand allocation for the generation function will differ from the allocation that is appropriate for the transmission function. This is particularly true where transmission for others across the utility system results in higher loading at times other than the native load system peak.

Transmission system loading on integrated utility systems is not solely a function of customer load on the system because of congestion management and centralized dispatch. For example, if load flows across the individual utility system because of lower cost generation, a transmission system may be fully loaded many more hours than retail customers' own load alone would indicate. Determination of the expected loading may also change because of events unrelated to the transmission facility owner, such as unit forced outages, changes in relative fuel costs, must-run generation and other factors that alter grid dispatch. The result of these factors is to change the allocation and cost responsibility for transmission in a way that impacts the appropriate demand period determination. To do this, it is important to understand the components of the transmission system and the cost drivers for each:

- **Generation laterals**: costs driven by connecting generation to the system and should be included in the generation/production demand costs.
- **Load laterals:** Costs driven by the loads on the lateral and may differ from the system or the transmission peak. Costs for load laterals are recovered through the distribution facilities demand charge.
- **Bulk transmission system**: Costs driven by loading of the bulk system and are recovered based on the load characteristics of the system. Options include:
  - Maximum load occurs in each month of the year: The demand charge is based on the peak period demand within every month and is the basis for the transmission demand charge.
  - Maximum load occurs in summer: If system is loaded only during four summer months, then the costs would be based on demand that occurs during the peak demand time period, even though the charges are billed over all 12 months. In essence, the non-seasonal demand would be equal to the average of the four critical peak demand periods.

Derivation of the Distribution Demand Charge

Distribution demand costs are driven by the customer peak load whenever it occurs. These costs are not identifiable on a time-of-use basis and the individual customer's maximum demand or contract demand (the maximum obligation of the utility to provide the local distribution service) is the appropriate demand measure to use to recover such costs. Any distribution costs not recovered in the customer cost category and the portion of transmission costs for load laterals are recovered in the distribution demand charge. The distribution demand charge would include a 100 percent demand ratchet based on either the customer's contract or actual demand.

As a general rule, the distribution system components peak at times that may not be coincident with the generation or transmission peak load. In planning and designing the distribution system, an important design element is natural load diversity that occurs based on the electricity use of the premise (businesses and residences have differing time patterns of load).

Certain activities, such as storage may alter the natural diversity of loads. For example, controlling electric water heaters by shutting them off for extended peak periods results in much higher coincident peak demands on delivery facilities because the natural load diversity is disrupted by the added control. The result is both higher distribution costs and higher peak demands for customers subject to control. Based on experience with time-of-use rates, there is potential for a similar impact on the distribution peaks and the cost of delivery service.

The recovery of distribution-related costs based on maximum demand whenever it occurs is fundamental to cost-based rates.

The three components of the distribution demand charge are recognized in the cost allocation process and relate to substation costs, primary facilities and secondary facilities not recovered in the customer charge. Conceptually, in a modern electric system all secondary costs should be customer-related. The allocation process recognizes that diversity increases as the load is measured further from the customer's individual load. To the extent that loads are homogeneous, a single distribution demand charge would be adequate. If there is little homogeneity, then the costs may need to be broken out separately but billed under the same 100 percent ratchet provision.

The customer and ratcheted demand charges would be based on an annual cost payable in 12 equal amounts. These annual charges would be premise-based so that a new customer occupying the premise would have his bills initially based on the premise's measures of demand. In addition, if a customer has service turned off at the premise and subsequently turns service back on, the customer would be responsible for the payment of fixed charges for the period where service was not taken as part of the cost of establishing service. Non-ratcheted demand charges would be based on the actual monthly use of demand.

Derivation of the Energy Charge

The final component of the unbundled rate design is the energy charge. The energy charge recovers all of the variable costs associated with the production or purchase of power. Further, the energy charge is not part of the utility's base rate. Rather, it is reflected in a full tracking fuel clause that recovers not only fuel and purchased power, but also variable production costs, environmental costs (e.g., scrubber chemicals), variable charges from the RTO or ISO, and any other costs that change with the consumption of energy.

The energy charge is subject to regular adjustments, like a fuel clause, and includes a deferral account that matches these costs dollar for dollar. The energy charges under this charge are differentiated based on cost causation by season, by time of use, by voltage level of service and, where applicable, by critical periods above and beyond the time of use periods. The adjustments to this charge are always seasonal-based adjustments in the sense that over or under recoveries of cost in a season are subsequently recovered in that season.

Energy charges may not require the inclusion of all of the cost components described above. For example, some utilities may not have distinct seasons. Others may have diurnal cost differences that are so small that there is no reason to separately bill for those differences. Some utilities with little diurnal difference may instead have critical peak periods when, for a few hours per month or for a few hours per season, they may experience costs far in excess of typical average or marginal cost levels. For example, the average cost might be approximate $35 per MWh for 97 percent of the time, but could easily exceed $100 per MWh in the remaining hours. In this case, the ability to provide proper price signals to customers would be important as would rate provisions designed to match costs and revenues under the critical peak period.

ILLUSTRATIVE RATE STRUCTURES

Using the concept of fully unbundled rates means that a utility's traditional rate class definitions are no longer as important. Cost-based rates enable the use of a less homogeneous class of customers, (e.g., there is no need to have one or more residential classes of service). There will no longer be a need for separate rate classes for certain end-uses, such as churches or schools, to reflect their different load characteristics compared to those of other general service customers. The ability to recover costs based on individual load characteristics then allows for rates based on other relevant conditions of service that have specific cost implications, such as voltage level of service or transformer or substation ownership.

Thinking about the factors that impact cost must begin with the customer component of costs including meter and service investment. This classification should also recognize that voltage level of service is of particular importance. In that context, it is possible to define a Small General Service Secondary Voltage Class. This class would consist of all customers who have essentially the same types of meter installations and service lines (e.g., residential, residential space heating, small commercial, small commercial all electric, etc.). Differences in other characteristics of utility service, such as demand coincidence factors and individual maximum demands, would not matter since the costs that are caused by these demand measures are already unbundled. The important point is to derive each component of the rate structure to reflect the actual cost of service.

Other classes would include General Service Primary Voltage, General Service Primary Voltage Transformer Ownership, Large General Service Substation, Large General Service Transmission, Non-Firm Service Rates and Back-Up and Standby Service Rates. These rates would reflect the different costs associated with each service and, as appropriate, seasonal, time of use and critical peak pricing-type considerations based on service level requirements and associated costs.

Customers who require unique service arrangements would have those costs recovered in a separate monthly fixed charge for directly-assigned facilities. For example, an industrial customer may take service at the substation, but require one or more dedicated lines to connect the substation to its facility. In that instance, the dedicated lines would be a directly-assigned cost and recovered under a separate charge unrelated to the customer's actual load.

To illustrate these concepts, the following tables outline the rate forms for General Service Secondary Voltage Class and General Service Primary Voltage Class customers.

Rates for the General Service Secondary Voltage Class assume the following operating conditions:

- All customers have the same meter costs and the average cost of secondary service lines consistent with the applicable line extension policy (customer's requiring a greater level of service investment make an appropriate contribution for the excess investment).
- Customer costs include a minimum system component for local distribution facilities at the secondary level.
- All primary related costs are included in the distribution demand charge.
- The utility is strongly summer-peaking for the 4 months, June through September.
- Partial requirements customers take service under this rate and the applicable back-up and standby service rate.
- Customers who require unique service arrangements either make a contribution in aid of construction for excess facilities or they pay a separate fixed charge.

Table 3 - Rate structure for General Service Secondary Voltage Class customers (i.e., residential)

RATE STRUCTURE (Billed amount)	TYPE OF CHARGE	DESCRIPTION OF CHARGE
Customer Charge $300.00/year or $25.00/month	Fixed	Charges that support the customer service functions of a utility (e.g., billing, meter reading, distribution connection)
Distribution Demand Charge $3.00/kilowatt of billed demand	Fixed	Charges resulting from the demand-related portions of the distribution system. This charge can be based on the greater of the current month's maximum demand, or the maximum demand occurring in any of the preceding 11 months.
Transmission Demand Charge $12.00/kilowatt year or $1.00/month	Fixed	This charge is for services provided by the bulk transmission system. It should be based on the rolling average of the maximum on-peak demand for the system
Production Demand Charge $96.00/kilowatt year or $8.00/month	Fixed	Includes the fixed costs of generation and the infrastructure that connects generation to the bulk transmission system.
Energy Charge Charges would vary based on time of use, such as $0.058/kWh for summer on-peak and $0.038/kWh for winter off-peak	Variable	Recovers all of the variable costs associated with the production or purchase of power, most notably fuel and environmental costs.

Charges based on a hypothetical vertically integrated electric utility providing a bundled service.

The rate components of a General Service Primary Voltage Class are outlined below assuming the following operating conditions:

- All customers have the same meter costs and the average cost of secondary service lines consistent with the applicable line extension policy (customer's requiring a greater level of service investment make an appropriate contribution for the excess investment).
- Customer costs include a minimum system component for local distribution facilities at the primary level.

- Remaining primary related costs are included in the distribution demand charge.
- The utility is strongly summer-peaking for the 4 months, June through September.
- Partial requirements customers take service under this rate and the applicable back-up and standby service rate.
- Customers who require unique service arrangements either make a contribution in aid of construction for excess facilities or they pay a separate fixed charge.

Table 4 - Rate structure for General Service Primary Voltage Class

RATE STRUCTURE (Billed amount)	TYPE OF CHARGE	DESCRIPTION OF CHARGE
Annual Customer Charge $600.00/year or $50.00/month	Fixed	Charges that support the customer service functions of a utility (e.g., billing, meter reading, distribution connection)
Primary Distribution Facilities Demand Charge $24.00/year or $2.00/kilowatt of billed demand	Fixed	Charge based on the greater of the current month's maximum demand or the maximum demand occurring in any of the preceding 11 months payable in monthly installments.
Transmission System Demand Charge $11.75/kW-year or $0.98/month	Fixed	Charge based on the rolling average of the maximum on-peak demand occurring in the hours of 12 noon through 9 pm weekdays in the months of June through September payable in twelve monthly installments
Production Peak Demand Charge $94.00/kW-year or $7.84/month	Fixed	Charge based on the rolling average of the maximum peak demand occurring during the hours of 12 noon through 9 pm weekdays in the months of June through September payable in twelve monthly installments.
Production Base Load Demand Charge $6.86/kW per month	Fixed	Charge based on the actual maximum demand occurring monthly regardless of the time the demand occurred.
Energy Charges Variable	Variable	The energy charges hereunder shall be determined from time to time to recover the total variable costs associated with the production, purchase and delivery of energy to the Company's transmission system including any volumetric charges imposed under an RTO/ISO Tariff. The summer season is defined as the months of June through September. The charges effective for the twelve months commencing June 1, 2014 are as follows: • Summer On-Peak (Hours 10 AM to 11 PM weekdays excluding holidays) $0.568 per kWh • Summer Off-Peak (All other hours in the season) $0.0441 per kWh • Winter On-Peak (Hours 6 AM to 10 AM and 5 PM to 9 PM weekdays excluding holidays) $0.0451 per kWh • Winter Off-Peak (All other hours in the season) $0.0372 per kWh

As these two rate structures illustrate, many of the unit charges for primary customers are lower because generation and transmission capacity related costs reflect lower primary voltage losses. For primary distribution costs, the lower charge represents the exclusion of secondary facilities from the cost of service at the distribution level. The lower energy-related charges are also the result of lower losses. The higher customer charge reflects higher metering and service costs, including using primary minimum system costs for service at this level. This general pattern will be repeated for each additional rate schedule with charges declining as the result of fewer facilities and lower losses. In addition, charges such as the residual generation costs or transmission costs will differ based on class load characteristics.

ROLE OF ADVANCED TECHNOLOGIES

Perhaps the primary reason rate structures have not changed significantly during the past century was due to a lack of technology to measure and appropriately charge for a variety of utility services. Until recently, utilities did not possess the technology and capability for measuring and recording data for each of its individual cost drivers.

Today's smart meters and advanced metering infrastructure (AMI) enable utilities to measure more than monthly kWh consumption. The technologies and back office software programs enable utilities to produce dynamic pricing information for customers and measure, record, bill and credit based on the usage levels of each service. Examples of additional services advanced technologies can track include:

- Time differentiated energy costs including critical peak prices;
- Demands by time of use and by maximum demand regardless of time; and
- Power factor measurement.

Smart meters permit a wider variety and type of price signals that can remove rate subsidies and send better, more cost-effective price signals to customers. With smart meters, each different rate component may be billed separately, enabling customers to pay for only the services they use.

OTHER CONSIDERATIONS

In addition to the various unbundled charges described above, it will be important to overlay seasonal and diurnal cost characteristics, critical peak pricing and time-of-use pricing, load control credits and other yet to be developed programs that reduce loads and create cost savings that would not be reflected in rates. Thus, we would expect to see energy prices that vary by season and by time of day based on time periods defined by cost differences, where appropriate. It will be important to develop seasonal and diurnal periods based on the underlying marginal costs recognizing that for some utilities those periods may vary in different parts of their systems. This would be the case where a portion of the utility delivery system is served off an electrically isolated load node of the transmission system. Where the system receives service from isolated facilities, the cost of these facilities and service should be borne only by the customers using these services. If the system is fully integrated, the costs of different nodes should be averaged across those nodes.

It is also important to remember that because unbundled rates eliminate intra-class subsidies that are included in many of today's traditional rate structures, certain policy goals could no longer be viably reflected as part of the rate. As such, programs such as low income bill assistance would need to be addressed indirectly through fixed bill credits funded by a separate rate component.

Ultimately these unbundled rates will be designed to recover the utility's class-related revenue requirements. The resulting price signals will be significantly more efficient from an economic perspective resulting in less resource waste and more economically efficient power systems. A key element of the successful implementation of unbundled rates will be to educate customers on how the rates reflect the underlying costs of particular utility services and how the customer can manage electricity use to reduce those costs. Overall, such rates are expected to generate efficiency gains for both customers and the utility.

The benefits of unbundled Smart Rates will accrue to every stakeholder group even though some members will pay more for the services they buy and others will pay less. Customers who pay more benefit from receiving the correct price signal and understand the benefits of alternative choices related to DSM and DG investments. For the utility, unbundled rates will not change the utility's revenue requirement in total, but will impact the stability of revenues favorably and will cause the utility to be more proactive in its marketing of unbundled services to customers. It will likely take substantial effort on the part of the utility to educate stakeholders of these benefits in a rising cost environment. It is the Smart Rates that will allow customers to use electricity more efficiently and allow the utility to recover its costs from customers who cause those costs to be incurred. While the utility will be economically indifferent as rate designs change, it will also benefit from better price signals as consumers adapt to the cost causative factors that form the basis for unbundled rates. Changing rate design will also impact customers who have made investments based on the economic signals of the 19th Century rates and some of those investments will no longer be cost effective. The issue of customer stranded costs will be a difficult element of the transition, but is inevitable because of technological advances in metering and in utility operations.

The end result of unbundled rates will be a more cost effective and better integrated utility system to the benefit of economic growth and new investments that enhance the efficiency of the utility grid. This new customer paradigm is a prerequisite for improving the safety and reliability of the utility system.

Appendix A

As electric rates become unbundled, it is important to understand the concept of demand billing. The concept of demand billing is one of measuring the maximum capacity of the electric utility's system used in any particular period of measurement. Load varies from moment to moment based on the actual use of electric appliances including motor loads such as compressors in HVAC systems or refrigerators and freezers. Lighting load varies even from minute to minute as lights are turned on and off. Some loads run continuously while other loads operate infrequently. The net result is that any particular customer can have a different load shape on a daily basis.

Figure A-1 Daily Residential Hourly Load Shape

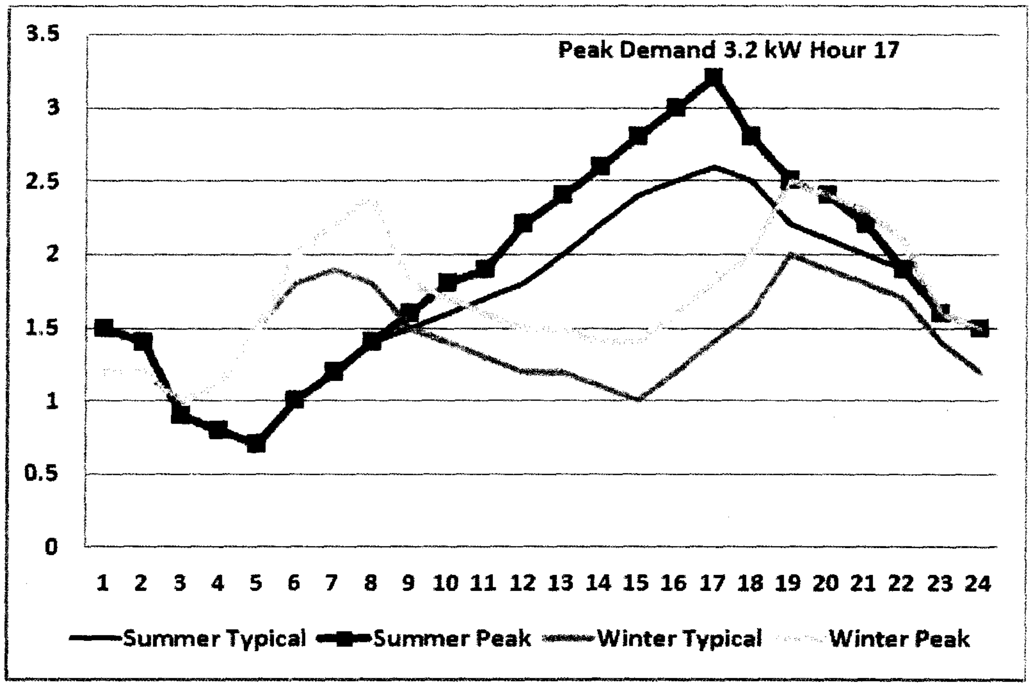


Figure A-1 shows a typical day summer and winter load shape and the peak day for both seasons. The peak hour demand for this customer occurs in the summer and is 3.2 kW. This is the customer's non-coincident peak demand based on an hourly measure. Hourly demand averages the kWh usage over the underlying measurement interval. For example, this demand may be average over four-15 minute intervals as illustrated in Figure A-2.

Figure A-2 Summer Peak Hour kW per Interval

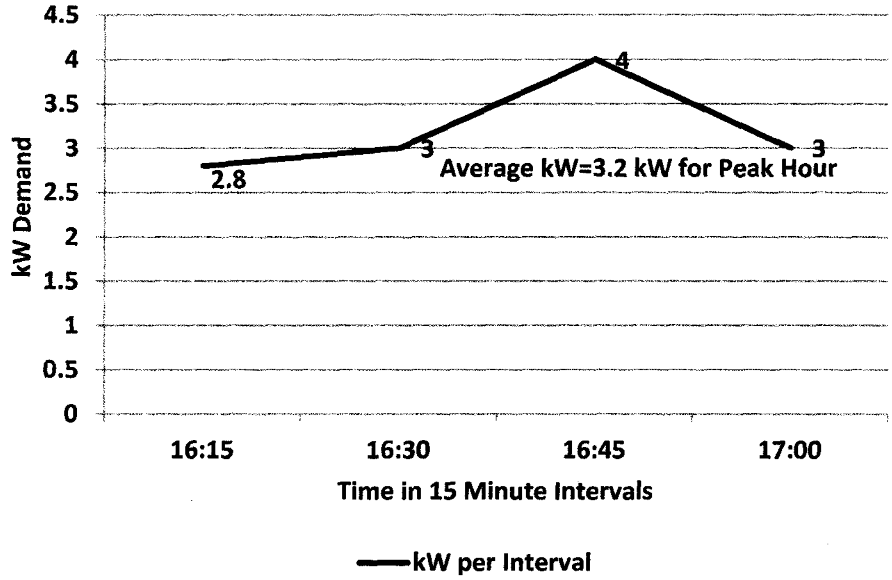


Figure A-2 illustrates the averaging of four-15 minute intervals to derive the customer's maximum demand. Maximum demand is also measured using shorter intervals. Table A-1 provides the demand in kW for each of the three possible measurement intervals.

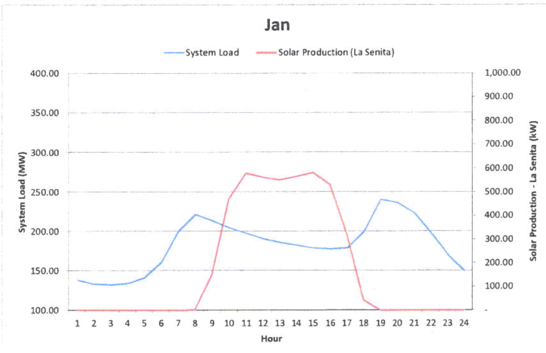
INTERVAL	kW DEMAND
15 Minutes	4 kW
30 Minutes	3.5 kW
60 Minutes	3.2 kW

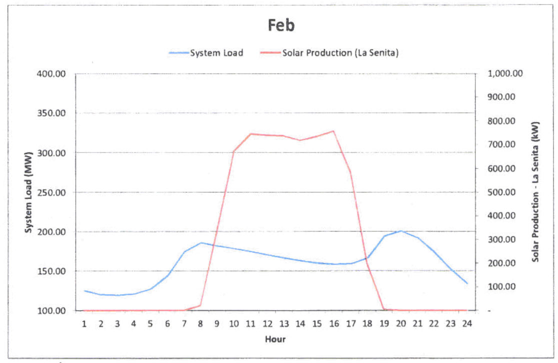
Since the kW measure of capacity required to meet the customer's load is the maximum demand on the utility system, the 15-minute interval is more representative of the required capacity for the utility's local distribution facilities. In any event, the choice of the measurement interval has little impact on customers' bills except for customers with highly variable loads. The reason for this is the costs are fixed and the higher measure of demand results in a lower unit charge for the customer.

As discussed earlier, there are many different billing demands that are relevant for cost recovery purposes. The same method of calculation is used in each instance although the hour or hours of measurement may differ. That is, some measures of demand might be defined as occurring within a specific range of hours. For example, the demand may be defined as occurring between the hours of 1 p.m. and -4 p.m. Since our data is reported on an hour-ended basis, the peak demand would be measured as the maximum demand occurring during the hours of 14 through 16 above. In that case, the demand would be 3 kW occurring at hour 16.

Exhibit HEO-1

LA SENITA


Jan
System Load
Solar Production (La Senita)
System Load (MW)
Solar Production - La Senita (kW)
Hour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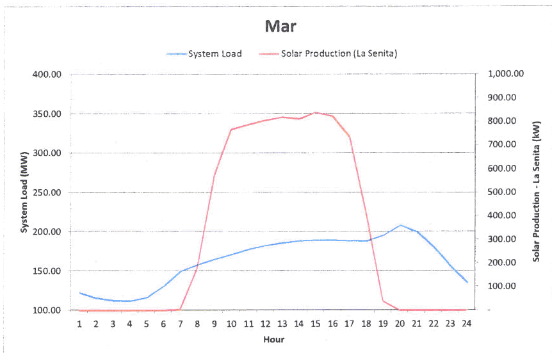
System Load (MW)
Solar Production - La Senita (kW)
Hour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System Load
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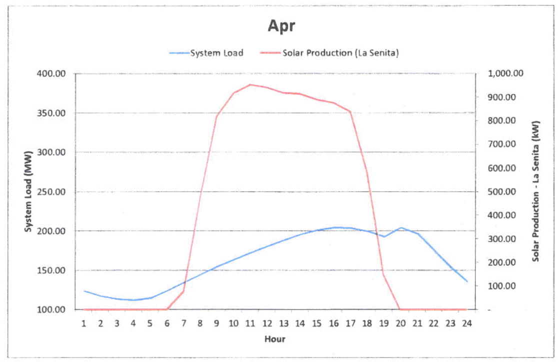
System Load (MW)
Solar Production - La Senita (kW)
Hour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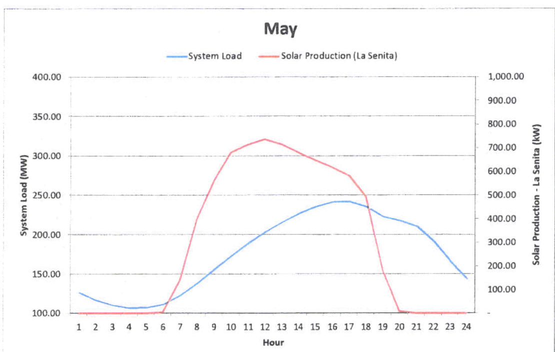
System Load (MW)
Solar Production - La Senita (kW)
Hour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System Load
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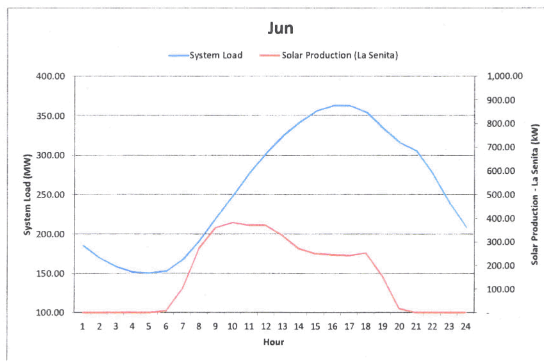
System Load (MW)
Solar Production - La Senita (kW)
Hour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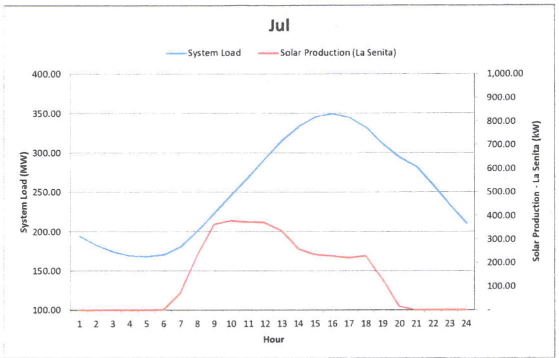
System Load (MW)
Solar Production - La Senita (kW)
Hour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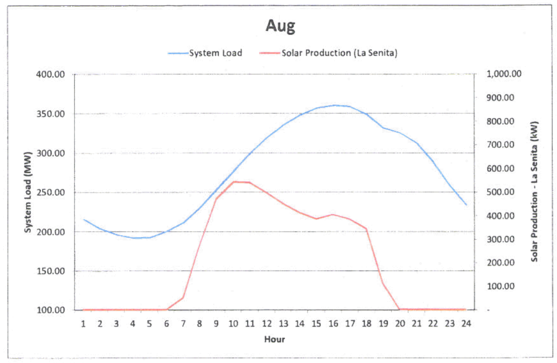
System Load
Solar Production (La Senita)
System Load (MW)
Solar Production - La Senita (kW)
Hour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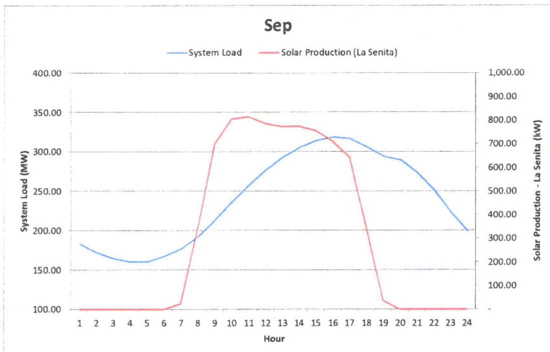
System Load
Solar Production (La Senita)
System Load (MW)
Solar Production - La Senita (kW)
Hour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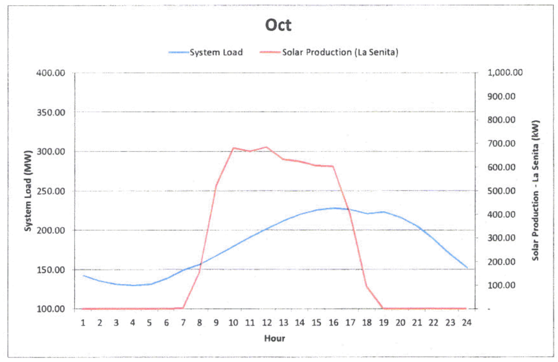
System Load
Solar Production (La Senita)
System Load (MW)
Solar Production - La Senita (kW)
Hour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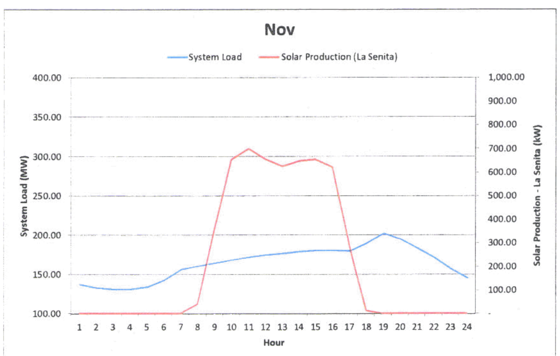
Solar Production (La Senita)
System Load (MW)
Solar Production - La Senita (kW)
Hour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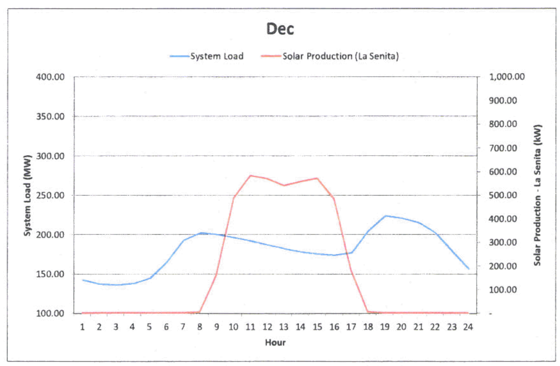
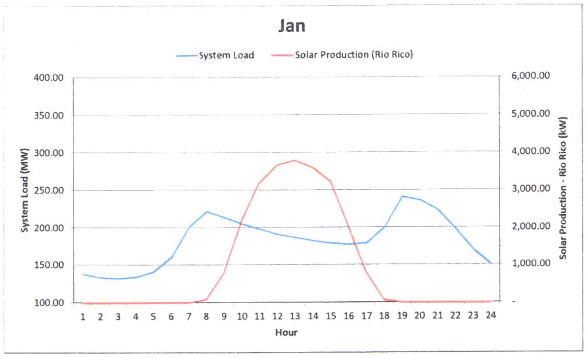
System Load
Solar Production (La Senita)
System Load (MW)
Solar Production - La Senita (kW)
Hour


Dec
System Load
Solar Production (La Senita)
System Load (MW)
Solar Production - La Senita (kW)
Hour

RIO RICO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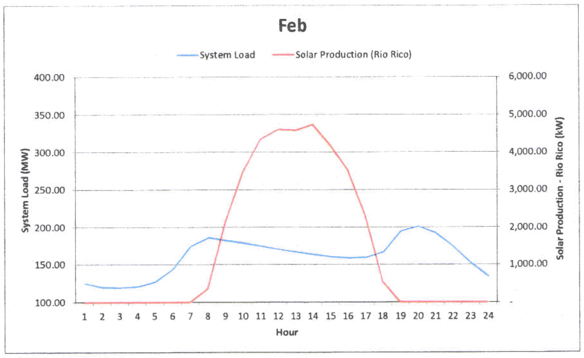
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour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System Load
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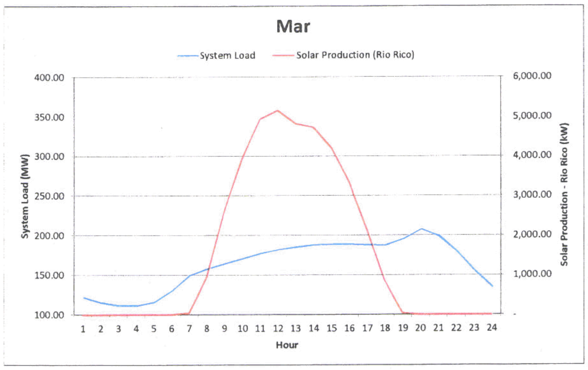
System Load (MW)
Solar Production - Rio Rico (kW)
Hour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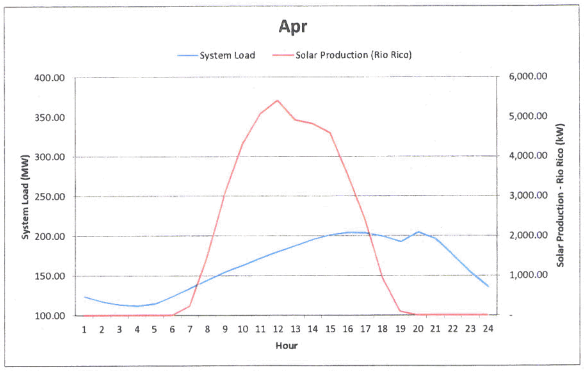
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour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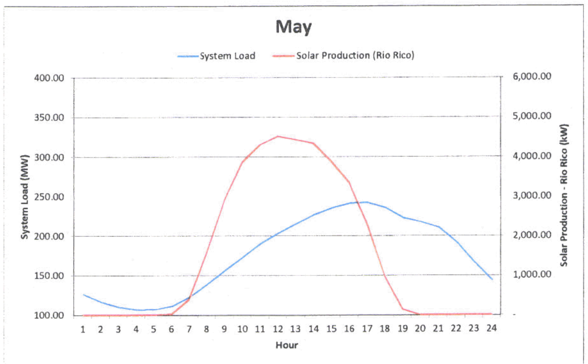
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour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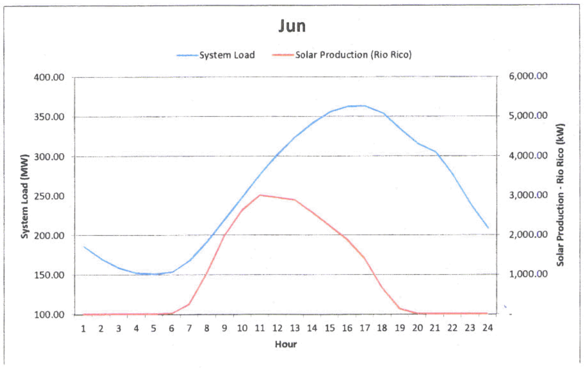
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour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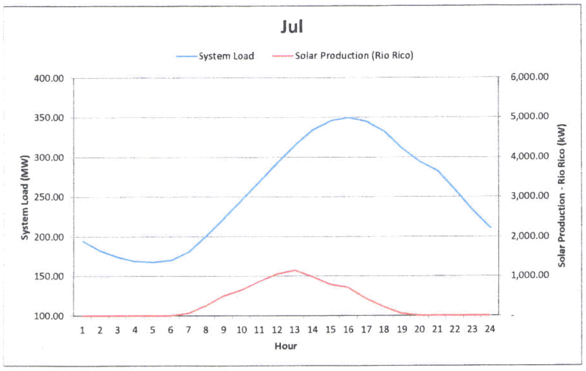
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour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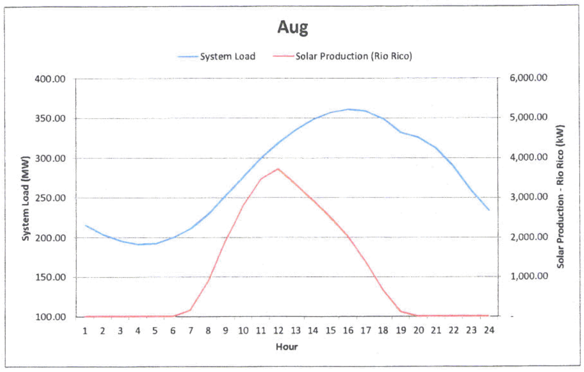
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour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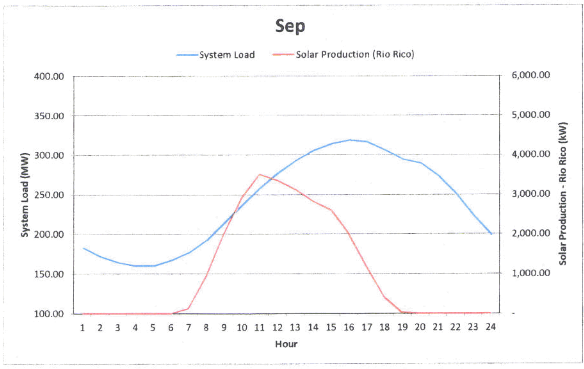
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour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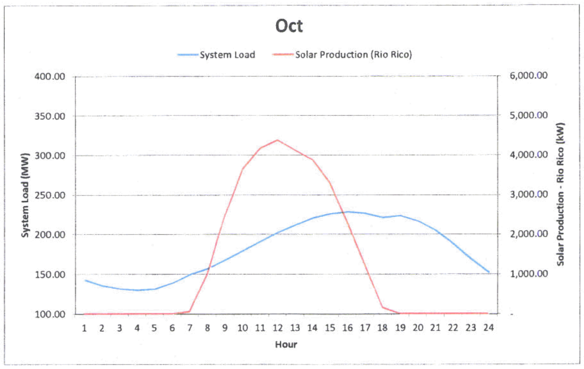
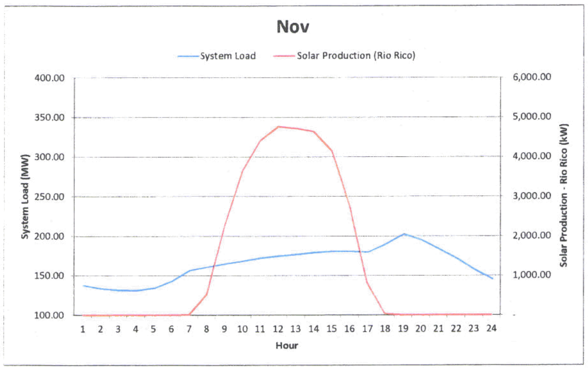
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour


Oct
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour


Nov
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

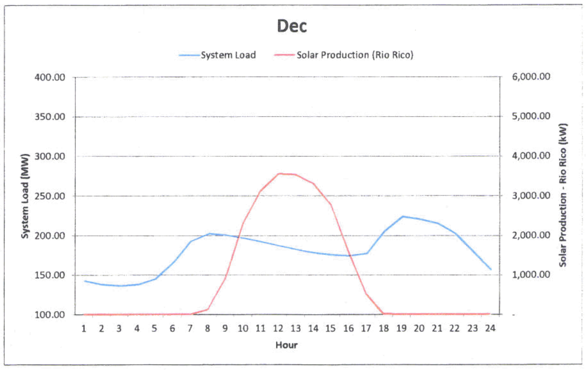
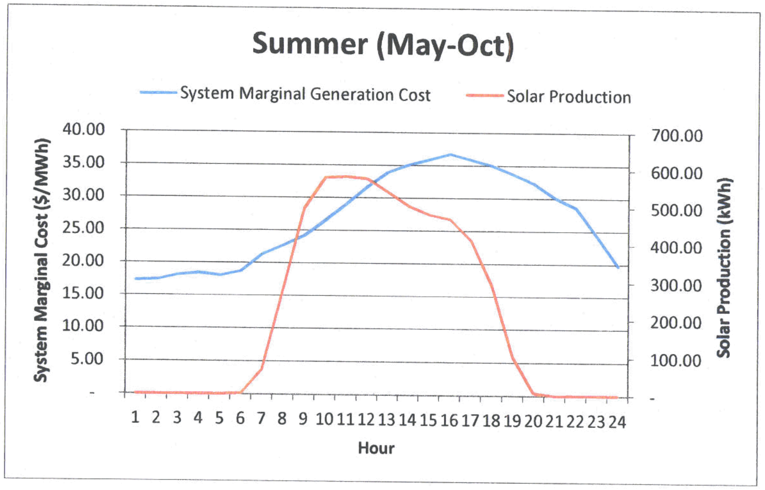
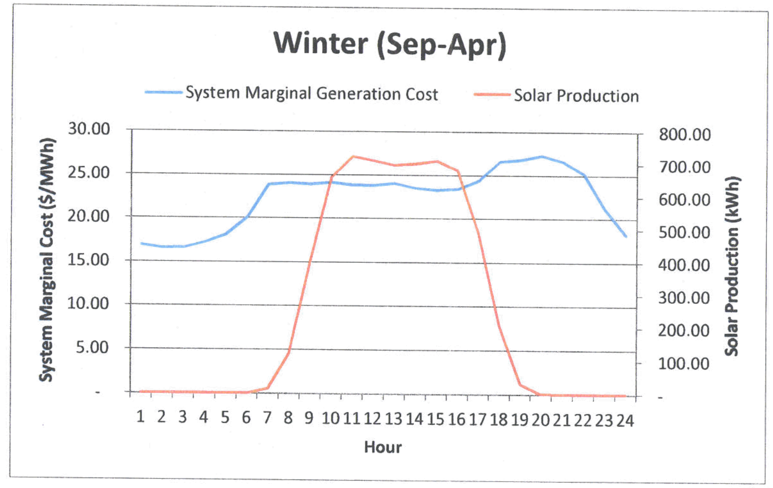

Dec
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

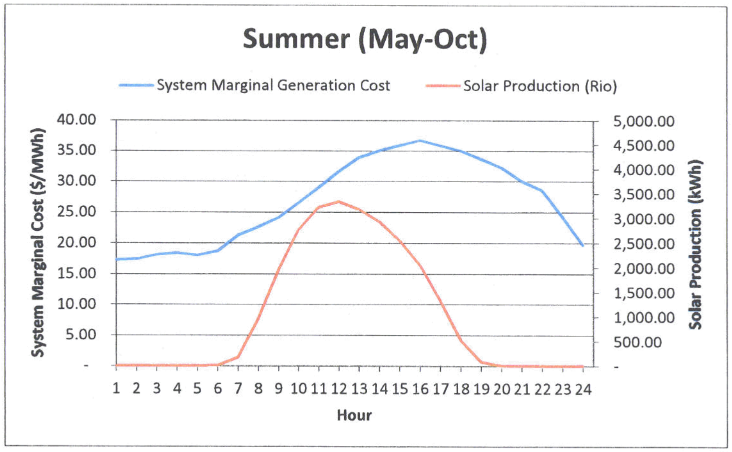
Exhibit HEO-2

LA SENITA


Summer (May-Oct)
System Marginal Generation Cost
Solar Production
System Marginal Cost ($/MWh)
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
-
700.00
600.00
500.00
400.00
300.00
200.00
100.00
-
Solar Production (kWh)
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour


Winter (Sep-Apr)
System Marginal Generation Cost
Solar Production
System Marginal Cost ($/MWh)
30.00
25.00
20.00
15.00
10.00
5.00
-
800.00
700.00
600.00
500.00
400.00
300.00
200.00
100.00
-
Solar Production (kWh)
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

RIO RICO


Summer (May-Oct)
System Marginal Generation Cost
Solar Production (Rio)
System Marginal Cost ($/MWh)
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
-
Solar Production (kWh)
5,000.00
4,500.00
4,000.00
3,500.00
3,000.00
2,500.00
2,000.00
1,500.00
1,000.00
500.00
-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

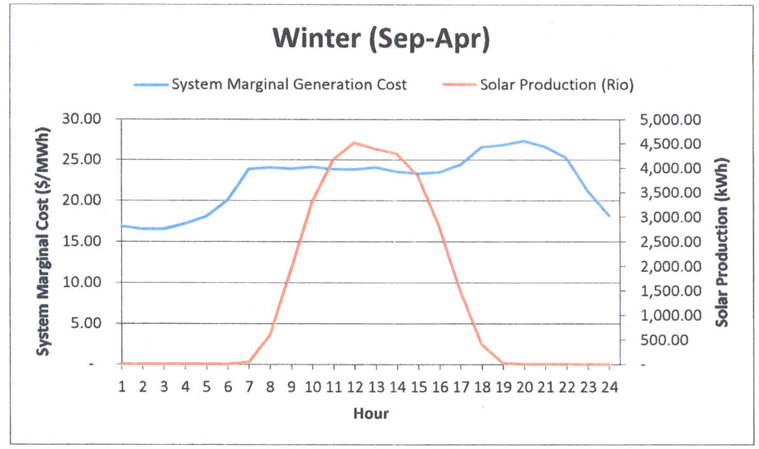
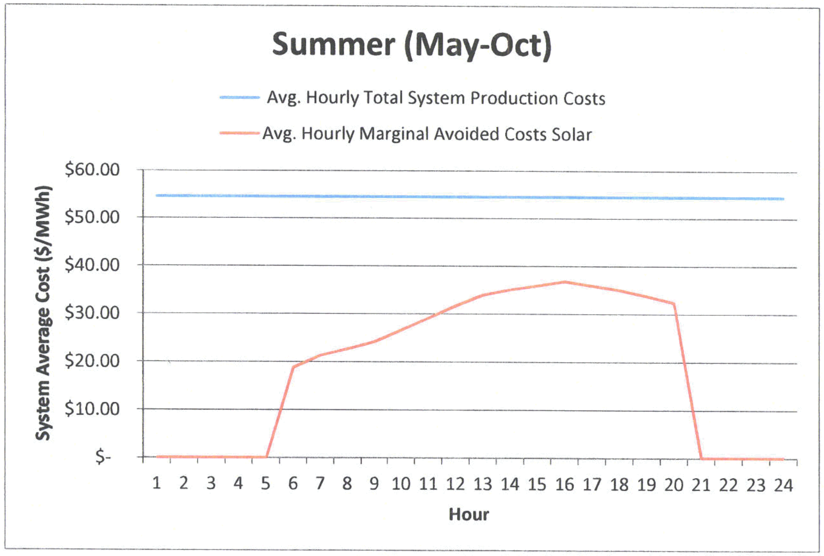
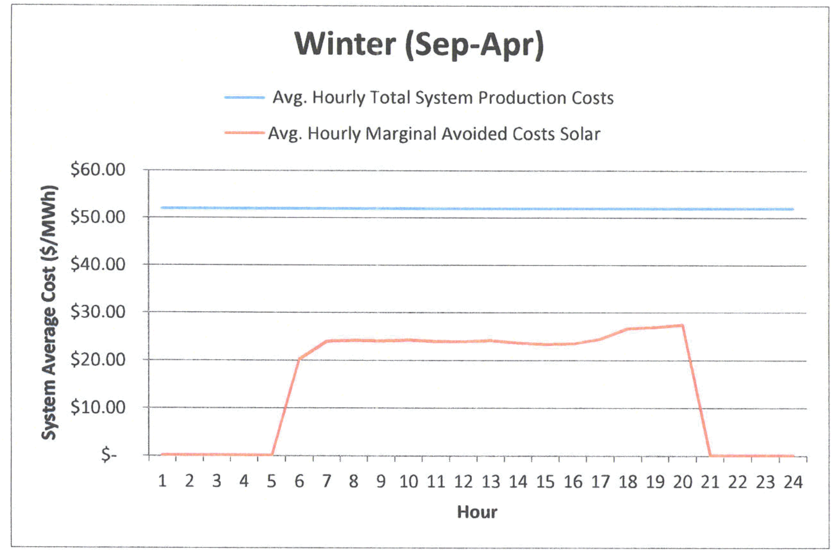

Winter (Sep-Apr)
System Marginal Generation Cost
Solar Production (Rio)
System Marginal Cost ($/MWh)
30.00
25.00
20.00
15.00
10.00
5.00
-
Solar Production (kWh)
5,000.00
4,500.00
4,000.00
3,500.00
3,000.00
2,500.00
2,000.00
1,500.00
1,000.00
500.00
-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

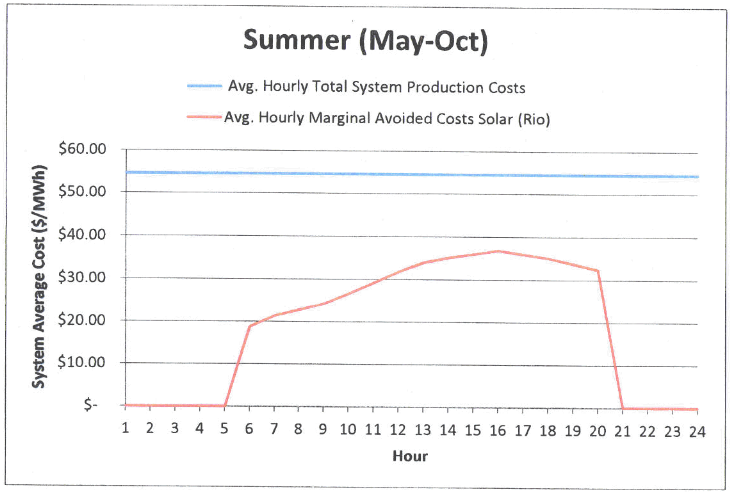
Exhibit HEO-3

LA SENITA


Summer (May-Oct)
Avg. Hourly Total System Production Costs
Avg. Hourly Marginal Avoided Costs Solar
System Average Cost ($/MWh)
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour


Winter (Sep-Apr)
Avg. Hourly Total System Production Costs
Avg. Hourly Marginal Avoided Costs Solar
System Average Cost ($/MWh)
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

RIO RICO


Summer (May-Oct)
Avg. Hourly Total System Production Costs
Avg. Hourly Marginal Avoided Costs Solar (Rio)
System Average Cost ($/MWh)
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

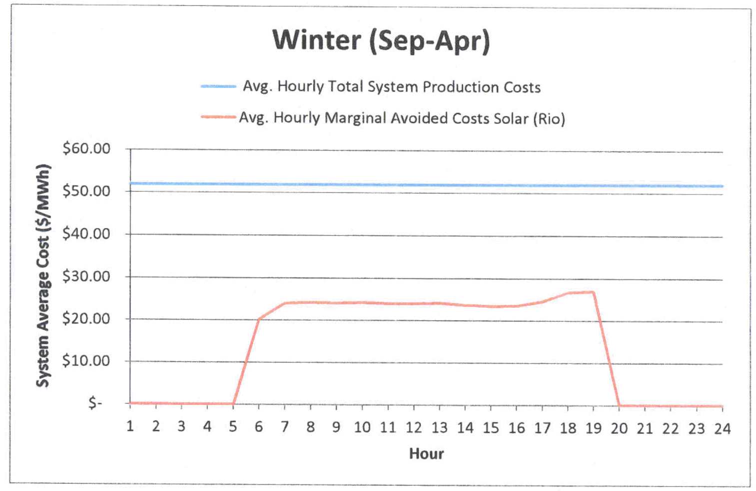
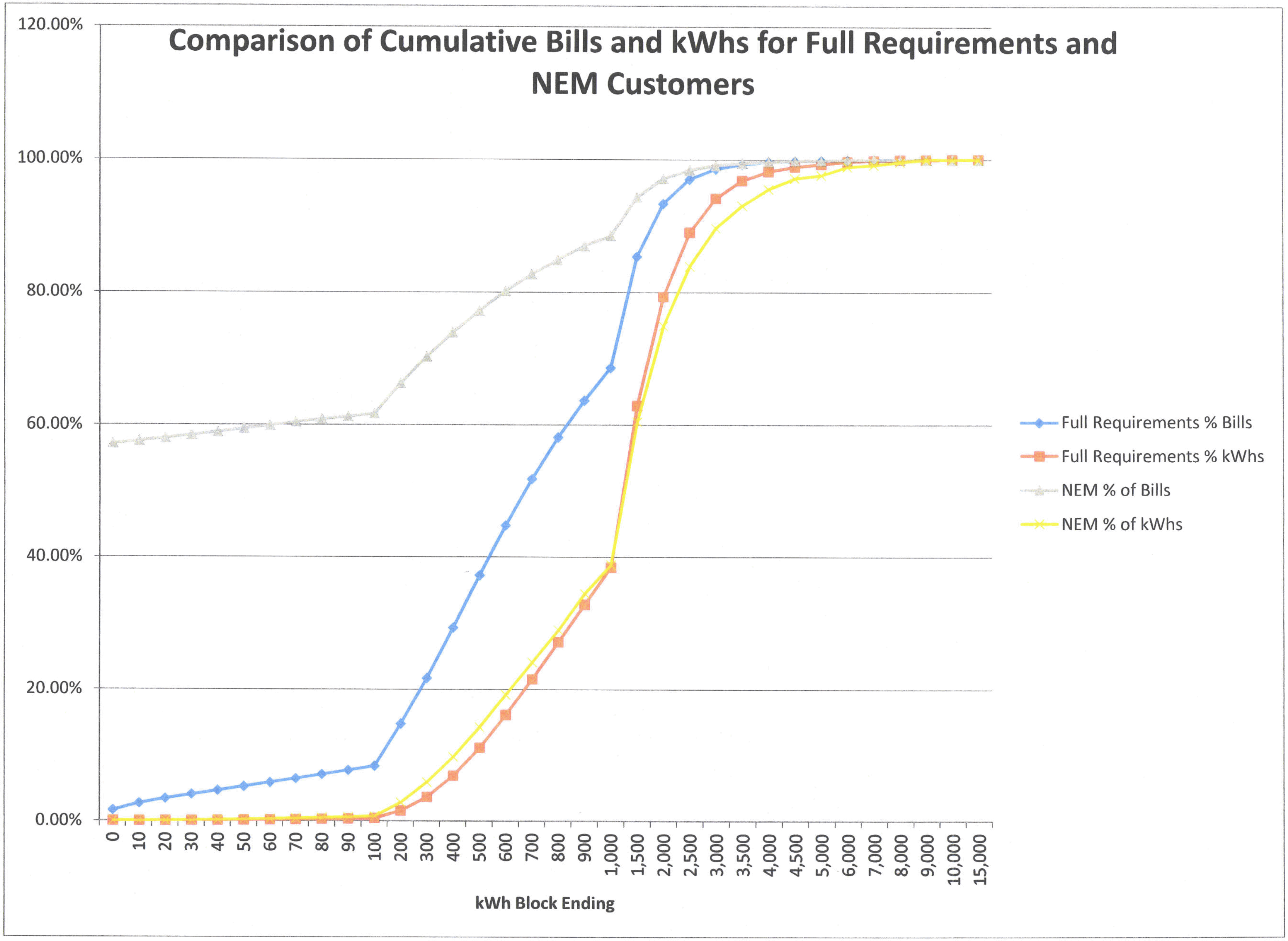

Winter (Sep-Apr)
Avg. Hourly Total System Production Costs
Avg. Hourly Marginal Avoided Costs Solar (Rio)
System Average Cost ($/MWh)
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Exhibit HEO-4



Comparison of Cumulative Bills and kWhs for Full Requirements and NEM Customers
120.00%
100.00%
80.00%
60.00%
40.00%
20.00%
0.00%
0
10
20
30
40
50
60
70
80
90
100
200
300
400
500
600
700
800
900
1,000
1,500
2,000
2,500
3,000
3,500
4,000
4,500
5,000
6,000
7,000
8,000
9,000
10,000
15,000
kWh Block Ending
Full Requirements % Bills
Full Requirements % kWhs
NEM % of Bills
NEM % of kWhs

Exhibit HEO-5

Make Free Demand Work For You

For the past five years, Butler REC has had a demand based rate. We thought it would be good to have a review on how you can take advantage of the rate to help save on your electric bill. The rate includes both a demand and an energy rate, thereby sending a price signal to the customer about these costs.

Back in 2009 we took the energy charge and divided it into energy and demand. We lowered the energy part of the bill by approximately 20 percent and moved that amount to a $5 per kW demand that is billed based on maximum hourly usage between 5 and 8 p.m. on weekdays. This design was based on feedback from our customer surveys, which showed a desire to have more control of your electric costs. Here is a quick review of the basics.

What is demand?

Electric demand refers to the maximum amount of electrical power that is being consumed at a given time, as opposed to energy which is the amount of power used over a period of time. For example, a typical clothes iron requires, or demands, 1,000 watts of power. If that iron is used for one hour it consumes 1,000 watt-hours or one kilowatt-hour of energy.

Using multiple appliances at the same time increases your demand. A typical dishwasher has a demand of 1,200 watts. If you used the dishwasher at the same time as the clothes iron, the total demand for these two appliances would be 1,000 watts plus 1,200 watts or 2,200 watts. If, instead, you choose to operate these at separate times, the maximum demand for these two appliances would only be 1,200 watts.

We have always had a demand charge. Historically, demand-related costs were included in the energy rate charged per kWh to residential and small commercial members. This was partially due to the higher cost of metering equipment required to measure demand. Members had no reason to reduce their demand as there was no immediate financial incentive.

With Butler's automated metering system, demand readings are readily available for residential and small commercial members. So historically you've always paid for the demand incurred by the cooperative, but now it will appear as a separate line item on your bill.

How is Demand Determined for residential and small commercial service?

As you are aware, you currently have a demand component on your bill, but how is demand determined?

Demand is FREE on weekdays any time prior to 5 p.m. and after 8 p.m. In addition to that, demand is FREE on weekends and most major holidays. This FREE demand has no effect on the minimum or billing demands mentioned later in this article. The demand you are billed for is determined by your highest hourly usage on weekdays between the hours of 5 p.m. and 8 p.m.

How is the Minimum Demand Determined?

The minimum demand is determined by taking 70 percent of the highest monthly demand of either July or August. The minimum demand is in effect for the months of September through June.

How is Demand Determined Throughout the Year?

- In July and August, the billing demand will be the highest hourly demand during the weekday peak hours (5 p.m. to 8 p.m.).
- For the months of September through June the billing demand will be the greater of:
  - The minimum demand, which is 70 percent of the highest monthly demand from the prior July and August billing demand, or
  - The highest hourly demand during the weekday peak hours (5 p.m. to 8 p.m.) of the current month.

	Monthly Demand KW	70 percent of Prior July/Aug Monthly Demand KW	Billing Demand KW
January	**6.2**	4.6	6.2
February	**6.3**	4.6	6.3
March	4.5	**4.6**	4.6
April	3.9	**4.6**	4.6
May	3.2	**4.6**	4.6
June	**6.1**	4.6	6.1
July	**6.6**		6.6
August	**6.2**		6.2
September	4.4	**4.6**	4.6
October	4.1	**4.6**	4.6
November	**5.6**	4.6	5.6
December	**6.5**	4.6	6.5

How is Billing Demand Determined?

Now that we know how your monthly demand and minimum demand are calculated we can determine the billing demand. For the months of July and August you are billed for your actual monthly demand. For the months of September through June we compare the actual monthly demand to your minimum demand. Whichever one is higher will be your billing demand.

Why July and August are important and how can I lower my bill?

From our example above we know that July and August will set our minimum demand for the rest of the year. So our goal is to manage our demand and take advantage of the FREE demand.

Your home's heating and cooling make up the majority of your bill. We are not asking you to do without cooling or heating your home, we just want you to be aware of the time frame and manage your home's energy consumption during that time.

Remember, you get FREE demand until 5 p.m. and after 8 p.m. on weekdays and all day on weekends and most major holidays. Operating appliances such as your dishwasher, oven, washer, and dryer outside of the time frame of 5 p.m. to 8 p.m. will help to lower your demand charge. If we can reduce this demand, we can reduce our annual cost of purchased power. This reduction in demand will help to keep future costs and rates down, as well as delay the need to build new generating plants.

How do I know what my household demand is?

The demand for a typical residential service ranges from five to 10 kW. **You can monitor your demand by clicking the Hourly Usage icon on the home page**. If you do not have internet access, the cooperative staff can provide you with your own historical demand. This will give you an idea on how you use electricity during the month.

What can I do to reduce my demand?

During times of peak demand, here are simple steps you can take to reduce electricity demand:

- Run large appliances such as washing machines, clothes dryers, and dishwashers outside the time frame of 5 p.m. to 8 p.m. on weekdays.
- Use the microwave or convection oven instead of the oven or range whenever possible.
- Run your electrically heated aboveground pool pump for just 12 hours per day (between the hours of 10 p.m. and 10 a.m.) instead of around the clock.
- Turn off all of the unnecessary lights around your home.
- Set the thermostat on the water heater to a lower temperature during the summer, such as 120 degrees.
- Use compact fluorescent light bulbs–they use 75 percent less electricity and last 10 times longer.
- When properly set, your programmable thermostat can help reduce your heating and cooling cost by up to 10 percent.
- Use ceiling fans to help circulate the cool air and make you feel cooler when you are in a room. In the summer the blades should rotate to move the air down to help produce a cooling breeze. In the winter, air should be moved upwards towards the ceiling to disperse the warm air that tends to accumulate there and distribute more evenly in the room.
- If you replace your refrigerator with an energy efficient one, properly dispose of the old one instead of continuing to use it as a secondary refrigerator. If you do use the old one, avoid keeping it on in the garage or other locations that get hot and humid. The refrigerator has to work harder in these areas to keep cool.
- Use and outdoor clothesline to dry items instead of your dryer. It will save you money and make your clothes smell great.

These are just some examples of ways to manage your demand. If you have more questions, call the office at 316-321-9600.

Manager's Report - December 2014

Your Holiday Refund is on its Way!

I hope you and your family had a great Thanksgiving and are looking forward to the Christmas season. It can be a wonderful time for families, but it can also be a time of sadness for those who have lost loved ones this past year. I hope you will join me in trying to be an encouragement for those individuals.

Great News–Holiday Refund is on it's Way!

We have some great news for you as a member of Butler REC. As a cooperative our objective is to run as efficiently as possible and only charge enough to operate and keep our mortgage obligations. So I am happy to tell you that you will be seeing a holiday refund on the bill you receive later this month. It should be one of the largest holiday refunds that we have given in Butler REC's history.

Several factors have made this refund possible. First, many of you conserved during the 5 to 8 p.m. peak times and that helped lower the cooperative's power cost. Those of you who participated saw immediate bill reductions, but it also helped our power cost overall. Those savings combined with Kansas Electric Power Cooperative (KEPCo), our power supplier, refinancing some of their debt at better terms, created more margins than we needed this year.

We also had a very good year with our propane division even though we executed several changes during the year to help propane customers save during what was one of the most volatile propane pricing years in history. When propane prices reached close to $5 per gallon, we waved the standard minimum gallon requirements in an attempt to help our customers get by until prices came down to a more reasonable level.

This fall we came out with prepay contracts well below what most of the competitors offered. We had an overwhelming number of you switch to our prepaid contracts for this winter.

So Merry Christmas and happy New Year from Butler REC, Regional Energy and Regional Media. We hope this holiday refund will help make your families holidays a little brighter.

Cost of Service Study

As you heard last month, it has been almost five years since our last rate adjustment and we are looking at a cost of service study. We are not planning on a rate increase for residential and most commercial members, but we are looking at a small increase in the customer and demand charge with a corresponding decrease in the kWh charge. In other words, this won't change the power costs of the average member in these classes. This will help make your electric bill less susceptible to extremely hot summers or cold winters.

2015 Budget & Work Plans

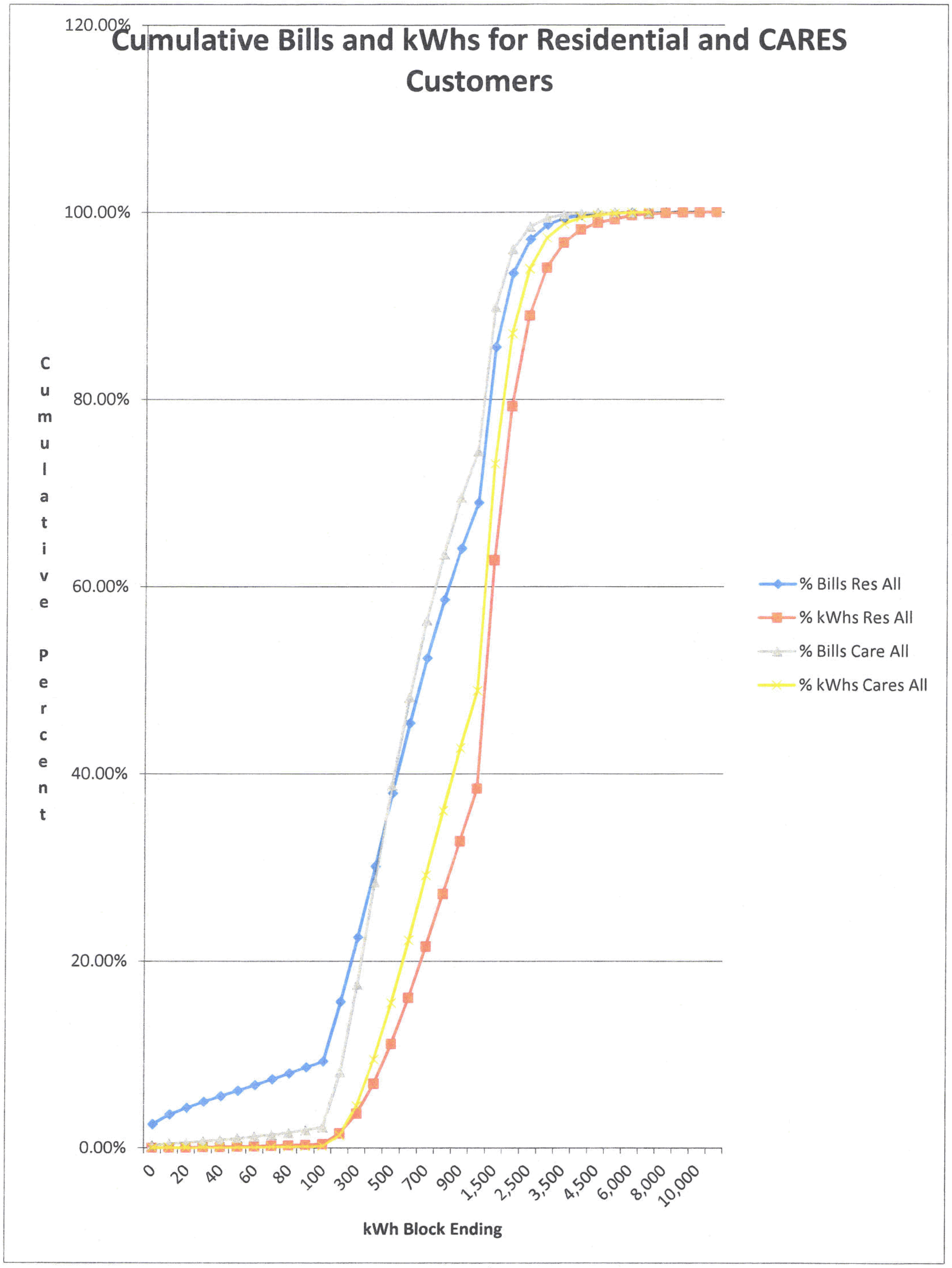
The co-op staff and Board of Trustees are currently working on the 2015 Budget and Work Plans. Items of importance that we are discussing include peaking generators, which could help our wholesale power cost and renewable generation including community solar and roof top projects. In addition, we are considering a residential insulation program that may help lower your power bill more than the cost of financing the insulation over time and, of course, the possibility of expanded right-of-way maintenance to help with reliability and blinking problems.

In closing, from all of us here at Butler REC have a great holiday season and a wonderful new year.

Robert "Dale" Short

Submitted by Butler REC on Fri, 2014/12/05 - 10:57am

Exhibit HEO-6



Cumulative Bills and kWhs for Residential and CARES Customers
Cumulative Percent
120.00%
100.00%
80.00%
60.00%
40.00%
20.00%
0.00%
0
20
40
60
80
100
300
500
700
900
1,500
2,500
3,500
4,500
6,000
8,000
10,000
kWh Block Ending
% Bills Res All
% kWhs Res All
% Bills Care All
% kWhs Cares All

BEFORE THE ARIZONA CORPORATION COMMISSION

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

EXHIBIT
UNSE-35
admitted

Rejoinder Testimony of

H. Edwin Overcast

on Behalf of

UNS Electric, Inc.

February 29, 2016

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. H. Edwin Overcast. My business address is P. O. Box 2946, McDonough, Georgia 30253.

Q. Did you file Direct or Rebuttal Testimony in this proceeding?

A. Yes. I filed rebuttal testimony in this proceeding.

Q. Which Commission Staff and/or Intervenor testimony do you address in your Rejoinder Testimony?

A. I will respond to the testimony of witness Fulmer of TASC, Witness Quinn of AURA, witness Alston of AURA, witness Rubin of AURA, witness Kobor of Vote Solar, witness Huber of RUCO, witness Zwick of ACCA, witness Wilson of Western Resource Advocates, and witness Schlegel of SWEEP. Since many of these witnesses cover the same issues, at some points I will refer to them collectively for ease of discussion

Q. How is your rejoinder testimony organized?

A. In addition to this Introduction, Section 2 provides some comments related to general arguments and conclusions made by these witnesses collectively in some cases or in general. Section 3 addresses cost allocation as it relates to the development of customer related costs. Section 4 addresses those witness who conclude that TOU rates without a demand charge provide a cost-based solution to the issues of cost recovery. Section 5 discusses the recommendation for a minimum bill. Section 6 corrects some broad-based misunderstandings about the measurement of demand. Section 7 provides a correction associated with the use of data that claims DG customers are like all other residential customers. Section 8 provides my summary and recommendations.

II. GENERAL ISSUES

Q. Do various witnesses make statements in support of their position that have common themes?

A. Yes. Several witnesses rely on the same article from the so called Regulatory Assistance Project (RAP) as support for their opposition to demand rates without making any effort to vet that article for theoretical or practical accuracy; witnesses also indicate broad agreement among other parties as a basis for concluding their position is correct; and witnesses claim that UNSE has not provided evidence to support its proposal.

Q. Please comment on the RAP article used to support the opposition to demand charges.

A. Unfortunately that reliance is misplaced. The RAP article, and by extension the witnesses relying on that article to develop opposition to demand charges, have failed to understand that the premises of the article are actually inconsistent with cost causation and even with the rationale for demand charges. From the beginning of the electric industry the pricing concept has been based on rates that include customer, demand and energy charges. Originally neither energy nor demand could be measured. Rates were typically "flat demand" rates- rates per kilowatt or per horsepower. In the 1890s two British engineers independently developed demand rates that have been applied in one form or another for over 100 years. Those rates are known by the names of the engineers who developed them- the Wright Rate and the Hopkinson Rate.

Initially it was not cost effective to measure power factor and demand for small customers and therefore "compromise rates are necessary, with the result that the demand charge is sometimes included as part of the energy charge."[1] (This is a point made by APS witness

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[1] Electric Utility Rate Economics, Russel E. Caywood, McGraw-Hill Book Company, Inc., 1972, p. 27.

Brown.) Thus the gold standard of cost-based rates-- billing customer, demand and energy charges has historically been uneconomic. With today's technology compromise is no longer necessary. This fundamental point is missed by all of those witnesses who oppose the demand charge. All residential customers and indeed all customers were billed on a demand basis in the early years of the industry. As early as 1956 Russell Caywood noted:

> "Demand charges have come in for serious consideration from the standpoint of the need for them in rates for small users and their relationship to the stability of revenue from larger customers. The more electrical devices that become available to the residential customer, the greater the variation in use of individual customers, both as to amount and the character of the load, i.e., the less homogeneous is the group. This suggests the desirability of using the demand charge to recognize differences in load factor."[2]

Turning to the key issues of the RAP article: "diversity, impact on low use customers (the vast majority of whom are low income), multi-family dwellings and time variation," [3] it is in fact diversity that necessitates the demand charges in residential rates as noted by Mr. Caywood above. I have explained the issue of demand diversity in great detail in my rebuttal testimony and will not repeat all of that discussion here. The concepts of capacity and demand are not a single number and the UNS proposal recognizes that fact. The key point is that an on-peak demand charge reflects the cost of generation capacity determined by coincident peaks (but allocated based on AED/4CP). Other demand costs based on customer NCP and class NCP are still recovered in energy charges with the shortcoming that solar DG customers still avoid some of the costs they cause and under net metering get too large a credit for costs they do not avoid. For example, the peak energy charge of over $0.10 per kWh plus the about $0.017 base energy charge per kWh exceeds the highest

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[2] Id., p.78

[3] "Use Great Caution in Design of Residential Demand Charges" Jim Lazar, FEBRUARY 2016, NATURAL GAS & ELECTRICITY, p.13

hourly marginal cost for the test year of $0.05915 per kWh by over $0.05 kWh. This remains as a subsidy for DG customers under net metering compared to avoided costs for ratemaking and adds to the bill credit an additional amount of subsidy under three part rates. The same is true for the winter off-peak charge that exceeds the winter marginal costs.

Low-use customer impacts is another issue and to be clear it must be analyzed independent of low income customer impacts because low use is not the same as low income; indeed the correlation of income and usage is weak or in some cases non-existent. The claim in the RAP article that the vast majority of low use bills are low income customers is not credible or supported by the data. Customers who are low usage customers on a year round basis have fewer electric loads than other customers and hence lower demand and use so there is no adverse impact unless the customer is a standalone, separately metered garage with an arc welder that is used. In that case the demand charge and the high impact are actually related to the cost to serve the customer. Other low use customers may be a lighted barn with no major demand, a boat house, a seasonal dwelling and the demand charge correctly recovers the cost based on the low load factor and so forth. In short, for true low use customers there is low demand and no adverse impact beyond eliminating the current subsidy, albeit still not a lot of dollars.

Multi-family dwellings are another example of lower use because of fewer major appliances. If they are electrically heated, as some are, the NCP loads will actually be highly correlated because they occur when temperature is the lowest. If not, there is diversity among the loads but billing maximum demand based on an allocation of NCP demand costs means that the charges are lower and the average payment reflects the average coincidence with the class NCP. This is in fact the kind of averaging that occurs naturally within a rate class but does not result in any major deviation in cost recovery because of the cost allocation based on class NCP. A simple example may help here. Suppose we have a class that is responsible for NCP dollars in the amount of $5000 annually. If the sum of 50 customers NCP average 4 kW per customer per month or 2400 kW billing units per year, the demand charge would be about $2 per kW or an average of $8 per month. The distribution system must be designed to meet the expected maximum demand of the customers when load is coincident on the delivery facilities. By definition of average that number must be larger than 4 kW per customer and at some point the aggregate load will exceed 200 kW by some amount requiring both larger wires and larger transformers than the typical residential customers. There is no reason to believe that payment based on the average of all these factors can result in a significant deviation from cost causation.

The issue of time variance actually demonstrates the same confusion that exists among various witnesses in this proceeding about cost causation. The statement in the article states that the demand charge must be focused on key peak hours to send the correct price signals. In this case, the article incorrectly assumes that all capacity costs are caused by a few peak hours. As I have explained in rebuttal, different capacity requirements are determined in different ways. While the conclusion about peak hours is correct for generation, it may not be true for any other functional cost category. It is easy to see that this is true simply by comparing the capacity of delivery substations and transformers to that of peak system demand. For the typical utility, delivery substation capacity is greater than peak load and the transformer capacity is also greater than substation capacity. Peak demand does not reflect cost causation for even all of the capacity cost of generation because some costs are incurred to produce lower cost energy and are properly recovered separate from the peak period demand charge that reflects marginal capacity costs. The article is neither theoretically sound nor does it reflect the practical aspects of utility planning and operations.

Q. Please explain the issue of general agreement as the basis for concluding that a position is correct.

A. To be clear, agreement among the parties is not the same as evidence. There are many examples of broad agreement that is incorrect. In this case, agreement among the parties does not get to the truth of the matter. The goal of any regulatory proceeding is to get to the truth of the matter based on credible evidence. General agreement is not evidence.

Q. Has the Company provided evidence to support its proposal?

A. Yes. The Company has provided evidence in this filing to support its filing. The purpose of the hearing is to determine if that evidence results in a decision supported by the facts and not the assertions unsupported by evidence.

III. CUSTOMER COSTS AND COST OF SERVICE

Q. Does a group of witnesses raise issues related to the allocation of customer costs?

A. Yes. A number of witnesses recommend the concept of the basic customer method for allocating customer costs in the cost study and determining the customer charge. There are two issues with the basic customer method that must be addressed separately. The first is the use of this method in cost allocation and the second is whether this method is valid for determining the customer charge. I will discuss both these issues.

Q. Is it reasonable to use the basic customer charge and NCP allocation of all other distribution in the cost study?

A. No. To begin, the classification is inconsistent with public utility accounting theory, the cost allocation as developed by NARUC, cost causation, empirical analysis and the economics of efficient rates for a utility that is a declining cost firm. I discuss each of the points below.

Q. Please explain the inconsistency with utility cost accounting and NARUC cost allocation.

A. In classifying all of the distribution plant in Accounts 364 through 368 to demand and allocating those plant costs on non-coincident peak (NCP), these positions do not fairly allocate plant to customer classes for a variety of reasons. As Dr. James Suelflow writes in his treatise Public Utility Accounting: Theory and Practice published by the Institute of Public Utilities at Michigan State University: "... distribution transformers and primary and secondary lines including conductors and devices (account 365 "Distribution Plant") and poles and towers (account 364 "Distribution"), all contain capacity and customer costs."[4] Dr. Suelflow recognizes that costs are more closely related to customers the closer one approaches the ultimate customer.

In other words, assets that are in closer proximity to the load served reflect less diversity and the classification of the costs associated with those assets should recognize this point. The recommendations advanced by these advocates of the basic customer method fail to recognize that class NCP is more appropriately used in 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.

Diversity can be seen by the fact that distribution substation transformer capacity is more than transmission transformer capacity measured in MVA. Typically, distribution transformer capacity is greater than substation capacity and that excludes all customer owned transformers that would increase the difference. These statistics further indicate the way diversity impacts loads as you move closer to customers. For that reason alone, those parties that support the basic customer method and class NCP demand allocation of accounts 364-368 are misguided because that allocation cannot be used as it does not

[4] Public Utility Accounting: Theory and Practice, James E. Suelflow, The Institute of Public Utilities at Michigan State University, 1974, p.241

reflect cost causation and cannot be relied upon as a basis for revenue allocation or for rate design.

Public utility regulatory accounting, including the NARUC Electric Utility Cost Allocation Manual ("NARUC Manual") supports the classification of distribution plant between customer and demand. In fact, the NARUC Manual does not even mention the basic customer method as an alternative for classifying and allocating distribution plant.

There is no question that the NARUC Manual states that the distribution plant costs in Accounts 364-368 have both a demand and a customer component. The NARUC Manual states "When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, *the utility must classify distribution plant data separately into demand- and customer- related costs.*"[5] (Emphasis added.)

This is not a new concept. In 1963 Constantine Bary published his treatise Operational Economics of Electrical Utilities. This rigorous study of utility costs and how loads cause those costs provides a summary chart of cost causation that is attached as Exhibit HEO- 1. This exhibit shows that a portion of the distribution plant beginning with primary lines is customer related. In the parlance of uniform system of accounts this is accounts 364-368.

Q. Is there empirical analysis to support the use of the minimum system?

A. By using class NCP as opposed to classifying these distribution accounts as customer and capacity, the parties incorrectly allocate more costs to larger customers who may not even use any of the facilities allocated to them. A simple example will illustrate this point. Consider a company with one industrial customer who has a 2500 kVa transformer

[5] Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, February 1991, p.95

installed. A typical installed cost for this transformer would be about $40,000. Also assume that the system served the same 2500 kVa of residential load using 50 50 kVa underground transformers that serve 400 residential customers. Those transformers typically cost about $4200 per transformer installed or about $210,000. Allocation of these costs on NCP would allocate the industrial customer $125,000[6] of rate base and the same amount to residential customers. Thus the advocates of the basic customer method would allocate less plant to residential customers than they actually use and at a lower cost than those actually caused by residential customers. The minimum system method would classify 70% of transformer cost on customers and the remainder would be allocated on capacity. That allocation results in about $193,000 of transformer costs to the residential class. Thus the minimum system method allocates cost more closely to causation and shares some of the scale economies between the customer classes. This same principle applies for conductor and for poles in the case that overhead transformers are used. Thus the basic customer method appears to be more results oriented than based on the principle that those customers who cause the costs should be responsible for the costs.

The fundamental point is that there are substantial economies of scale for all sizes of transformers, overhead and underground conductor and poles. In each case the per kVa cost of industrial transformers is below the cost for every size of residential transformer except for the largest and least used size of residential transformer. Some industrial transformers are even lower cost per kVa than the lowest cost single phase transformers used for residential customers. Using a demand allocation factor implicitly makes the incorrect assumption that the cost of transformer capacity is the same for all classes. It is not. This is the type of empirical analysis that is necessary to develop an appropriate determination of the best available method for allocating costs between classes. By classifying plant between customer and demand, the residential class receives a higher

[6] Based on 50% of the sum of the classes NCP

weighting of transformer costs consistent with cost causation since the unit costs per kVa for residential transformers is higher and they use many more transformers than other classes of customers. The basic customer charge method cannot recognize this reality. By allocating the cost of transformers on NCP only, the parties supporting the basic customer method unfairly and incorrectly allocate all of the economies of scale in transformer costs to the residential class and compounds that error by allocating fewer transformers to the class than residential customers actually use. Any witness advocating the use of the Basic Customer Method would produce a result that is inconsistent with cost causation as demonstrated above. Essentially, the basic customer method is not a method for calculating the customer component of costs that is based on the gold standard of cost causation because it fails to reflect any costs more than meter, service and direct customer accounting costs such as meter reading and billing in the customer costs.

The basic customer method relies on an empirically incorrect assumption. Similar economies of scale occur for other distribution accounts with the result that allocation without the minimum system significantly under allocates costs to the residential class and over allocates costs to larger demand customers who use far less of the distribution assets than residential customers. Since scale economies apply across all components of the minimum system including conductor and poles, the same conclusion applies to the other distribution accounts. For conductor, larger customers are typically located closer to substations than residential customers and therefore require less conductor. The NCP allocator over allocates distribution line significantly to larger customers and that does not take into account the lower unit cost per kVa of line capacity to serve these customers. Namely, absent the use of the minimum system the costs for smaller customers is under allocated and is over allocated for larger load customers.

Q. Is it fair to conclude that the advocates of the basic customer charge support the resulting higher energy charges in rates?

A. Yes. As the cost study filed by the Company illustrates, there are no energy-related costs for any component of the transmission or distribution costs and virtually none for production plant. Despite this fact, the parties who oppose demand charges have assumed that all of the fixed production, transmission and distribution costs should be allocated to the energy component of the rate and would have higher energy charges for all customers. By collecting costs that are demand related in energy charges the rates that result violate the matching principle, which provides that the rates charged should match the costs for all customers. Recovery of fixed costs in the energy component of the rate cannot match cost causation for demand unless all customers in a class have identical or near identical load factors. (This is the point noted by Caywood above.) That is not the case, particularly for solar DG customers. Failure to follow the minimum system classification and in addition putting these costs in the energy charge would unfairly cause customers who use more kWh to pay more for the same customer services provided to customers who consume less, and for customers with the same delivery services to pay more than identical customers with lower load factors. In the case of net metering, it also means that solar DG customers are not paying the actual cost of the facilities they use related to the distribution system. I should also note that it is not necessary to provide a separate class cost study for solar DG customers to reach this conclusion. It is as simple as the cost of service study allocates the minimum system costs and the class NCP costs and production demand costs properly to the residential class including the load shape of solar DG customers. In my view, this allocation is conservative because of the different load characteristics of DG solar customers. The problem is not that the cost of service study needs to be changed; it is the rate design that recovers the allocated fixed cost, both customer and demand, on energy. Since over half of the solar DG bills are for zero kWh, and nearly all of the bills do not exceed the first block, the company collects far less than the average class costs for those customers. It is impossible that solar DG produces revenue enough to cover their allocated costs with so few billed kWh.

Q. Some advocates of the basic customer charge method rely on Bonbright to support their method. Please comment.

A. I have discussed above that the accepted method for classifying these costs is to classify them as both demand and customer. Parties opposing various aspects of cost allocation use Bonbright to support the basic customer method. In fact, Bonbright states his position regarding customer costs as "operating and capital costs found to vary with the number of customers, regardless, or almost regardless, of power consumption."[7] I also note that Bonbright states that the minimum system costs should not be allocated to the customer component. Bonbright also continues on to say that the exclusion of minimum system costs from demand stands on "much firmer ground."[8] The key point is that customer costs vary with the number of customers. As I have shown above transformer and other distribution costs vary with the number of customers. Further the relationship between customers and cost is an empirical relationship that has been reviewed by economists. The correlation between customers and distribution costs has been confirmed by academic and regulatory research work related to estimating Total Factor Productivity (TFP) for use in price cap regulation where customers or connections has been an output measure for calculating the X-Factor in the formula P = I – X. The formula P= I – X is essentially a formula that relates either price or the functional equivalent revenue requirements to inflation and changes in productivity as measures by the relationship of physical outputs like customers and demand to measures of physical inputs such as meters or transformers. For example, the following statement from an Australian electric distribution TFP study says "The connection component recognises that some distribution outputs are related to the very existence of customers rather than either throughput or system line capacity. This

[7] Principles of Public Utility Rates, James C. Bonbright, 1961. p. 347
[8] P.348

will include customer service functions such as call centres and, more importantly, *connection related capacity (eg having more residential customers requires more small transformers and poles)*." (Emphasis added.) This information is developed specifically for a network electric utility providing delivery services. I would note that the emphasis on connections is the result of the correlation of distribution costs to the number of customers. In a more recent study related to the electric distribution utilities in Ontario, Canada, The Pacific Economics Group (PEG) found that customer number was an empirically significant output measure for determining productivity. In each case the productivity measure is used to determine the expected changes in costs over time. As an aside, the customer component of TFP has the largest cost elasticity weight meaning the customer component is more significant than the other output measures. In addition to Australia and Ontario, other jurisdictions such as Great Britain and the Netherlands also use customer numbers to develop TFP.

Based on this research, it is fair to conclude that the weight of modern empirical evidence is fully supportive of the minimum system use to classify distribution system costs in accounts 364-368 as both customer and demand. I conclude that this empirical evidence, not available in 1961, would have Bonbright supporting the minimum system because it aligns with his principle definition noted above. The goal in this case, as dictated by not only regulation but affirmed by the courts, is to allocate costs based on the principle of cost causation.

Q. Are there other authorities that support the use of the minimum system and demand charges?

A. Yes. Alfred Kahn clearly defines that the parameter of the defect in cost of service is where marginal costs diverge from average costs. That divergence occurs for any utility exhibiting economies of scale. Kahn also states that the full distribution of costs "is in part along the lines that reflect true causal responsibility."[9] He goes further in that same chapter to conclude that "for those segments of demand that do not have the requisite high elasticity—prices based on fully distributed costs have much to recommend them."[10] Kahn concludes by noting "the respective average historic cost responsibilities of the various classes of service plus proportionate contributions to overhead will most likely strike the various rate-payers as equitable and non-discriminatory."[11] There is nothing in Kahn's view that is in any way inconsistent with the Company's cost study. Kahn's views however are inconsistent with the those parties who advocate the basic customer method and inclusion of all costs in energy charges since they do not reflect cost causation as demonstrated by both theory and pragmatic analytics.

Q. What do you conclude about the use of the minimum system to classify cost between customer and demand?

A. Based on the above evidence, the minimum system classification reflects cost causation and is supported by regulatory accounting, the NARUC cost allocation manual, empirical evidence that is utility specific and empirical analysis that is applied to a wide array of utilities. The basic customer method must be rejected because the evidence shows it to be not cost based but outcome driven.

IV. <u>TWO PART TOU RATES</u>

Q. Do a number of intervenors support two-part TOU rates as a reasonable alternative to the proposed three-part of Staff and TEP?

A. Yes. A number of witness suggest that a TOU rate with a small customer charge is a better alternative rate design for residential customers than the three-part rate.

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[9] The Economics of Regulation: Principles and Institutions, Alfred E. Kahn, John Wiley and Sons, Inc., New York, Sixth Printing, 1995, p. 150
[10] P. 158
[11] P. 158

Q. Please describe the two-part TOU rate.

A. A two-part TOU rate essentially consists of a customer charge and energy charges that are differentiated by peak and off-peak periods which may also be seasonally differentiated. This rate means that all fixed costs above those recovered in the customer charge continue to be recovered in kWh charges. It makes the implicit assumptions that patterns of energy consumption correspond with the various demands on capacity and load characteristics are sufficiently homogeneous that such a rate will fairly recover the various demand related costs. It also ignores the issue that it is the energy component of the rate that is provided in a competitive market and the fixed costs components are in the regulated monopoly portion of the market. This latter point means that energy is the most elastic component and recovery of fixed costs in the energy charge cannot ever match costs and revenues for individual customers or even for classes of customers because it is not energy that causes the fixed costs. Rather, it is various measures of demand that cause those fixed costs.

Q. Why are two-part, TOU rates not a good alternative to three-part rates?

A. In simplest terms it is impossible for two-part rates to reflect cost causation for the same reason that two-part inverted block energy rates cannot track costs. The only costs that vary by time of use with kWh consumption are those costs classified as energy. In that regard, having energy charges that reflect marginal cost differences reflect cost causation much better than inverted block energy charges and would be consistent with Alfred Kahn's concern above where marginal and average costs diverge. When fixed costs are added to the TOU energy charges, rates no longer match cost causation. It is as simple as the fact that if the difference in marginal cost is two cents and the energy charges are loaded with higher on-peak fixed costs so that the differential is now five cents, the customer signal is that by saving or shifting a kWh the utilities costs decrease by five cents, customers make decisions assuming that there action saves the utility five cents. In reality, the action saves two cents and the other three cents is the same type of fixed cost subsidy that exists in current non-TOU rates. That subsidy either comes from other customers or utility shareholders or some combination of the two sources. In any event the result is inefficient choices and wasteful use of society's resources.

Q. What do you conclude about the viability of two-part TOU rates as an alternative to three-part rates?

A. It is impossible for TOU rates to be as efficient, equitable and cost based as the three-part rate. That rate design does not address issues of cross subsidy and inefficient pricing.

V. THE MINIMUM BILL

Q. Do several witnesses recommend a minimum bill to resolve the issue of fixed cost recovery?

A. Yes. There are two versions of the minimum bill. The version that seems to be recommended by the witnesses is to continue the two-part rate with a low customer charge and impose a higher minimum bill. Given that these witnesses rely on Bonbright, I am somewhat surprised by the recommendation, because Bonbright says "From the standpoint of cost analysis, it (the minimum bill) is decidedly inferior to an unqualified customer charge."[12]

Q. Why is the minimum bill not a good alternative to the customer charge?

A. Actually, the minimum bill is mathematically equivalent to a customer charge equal to the minimum bill and some number of free kWhs. To actually recover the required level of fixed cost, say $10.00, with a minimum bill the amount of the minimum bill with a $0.08 per kWh charge and an average energy cost of $0.04 would need to be calculated as $0.08 - $0.04 or $0.04 divided into $10 or 250 kWh. This calculation further assumes that the

[12] Principles of Public Utility Rates, 1988 Edition, p. 401

fixed costs associated with the first 250 kWhs are zero and they are not. As a result if you needed to collect the $10 in a minimum bill you would need a first block charge of $0.12 per kWh and a declining block rate. In fact, even with a small customer charge this was the rationale behind the declining block rate with a steep first block for kWh that nearly every customer used every month.

Q. Is a minimum bill a solution for recovering fixed customer related costs?

A. No. Customer costs are best recovered in a fully allocated customer charge with no free energy. It is a better price signal and more efficient for customers as well.

VI. MEASURING DEMAND

Q. Does there appear to be confusion about measuring demand?

A. Yes. Several witnesses have used the wattage of an appliance as a measure of demand and estimated the peak load of customers at levels that would not be found except for a few residential customers. Peak demand for residential customers based on an hour demand cannot be determined by appliance wattage alone because as with customer diversity there is also premise diversity.

Q. Please explain premise diversity.

A. First, not all appliances in the home run together and in most cases could not all run at once without overloading a circuit. Some appliances cycle on and off. The result is that there is some diversity in a dwelling that occurs naturally. To use an example from other testimony, a microwave oven may have a range of wattage from 600 watts to 1200 watts. This is a range of 0.6 kW to 1.2 kW of connected load. The measured demand for billing purposes is based on one hour. It is unlikely that a microwave ever runs continually for one hour. For example it takes one minute and 15 seconds to poach two eggs in my microwave. With other appliances running in an hour the microwave oven would add 0.025 kW to the hourly demand. Another appliance mentioned was a blow dryer at 1500 watts. Neither a blow dryer nor a microwave is likely to run for the whole hour so the contribution of the blow dryer will be a fraction of a kW even if it runs at the same time as the microwave. For larger appliances such as a water heater the issue of diversity also applies. Water heaters have two elements typically rated at 4.5 kW that will not operate together. The upper element comes on to raise the water temperature back to the setting or about 120 degrees. At 8 gallons the water heater uses at most 1.4 kW because it only needs to run for less than 20 minutes. Air conditioners also cycle if properly designed meaning they do not run continually. The whole point is that the witnesses who have calculated substantial kW loads are not taking into account how these appliances operate. Most appliances do not run at full load continuously for an hour. For example, in a recent analysis of customer loads based on load research, a customer with electric heat and using 24,000 kWh plus solar DG had an individual peak load of just less than 14 kW at the winter peak of the utility. Since it is likely that the resistance heat alone would be at least 15 kW installed, it is obvious that premise diversity occurs.

Q. **Are customer NCPs for low use customers likely to be as high as 18 kW claimed by witness Kobor, the 10 kW claimed by witness Schlegel or the 7 kW claimed by witness Zwick?**

A. No. The simplistic approach of adding kW ratings of appliances is not representative of how demand is measured for billing purposes and the recommended interval is one hour in this case. Just as an example, the typical range element on a stove to scramble some eggs uses about 1500 watts per hour. Eggs on the range take about five minutes or less so the use would be about .125 kW not 10 kW. If it had been a fifteen minute interval the actual charge to recover the same demand costs as the hourly demand would have been much less than the proposed demand charge.

VII. SOLAR DG CUSTOMERS ARE NOT LIKE OTHER RESIDENTIAL CUSTOMERS

Q. Witness Kobor claims that the data you used to show that solar DG customers are different from standard customers shows just the opposite. Please comment on this claim.

A. The conclusions reached by witness Kobor are based on a number of errors. First, her conclusions that the bill frequency data demonstrates that NEM customer bills are not outliers but fall within the range of variance for the system as a whole is simply wrong. In reaching this conclusion witness Kobor has failed to account for difference in the number of customers in the NEM frequency as compared to the non-NEM frequency. She concludes that because the non-NEM customers have more zero bills than NEM customers these customers are just like the residential class. For NEM customers the bill frequency demonstrates that 6.8 bills per customer are for zero kWh while for non-NEM customers only one bill out of every 50 bills is for zero kWh. The frequency also shows that the average NEM bill is for 330 kWhs meaning that average NEM bill does not even get out of the lowest cost first energy block of the rate. (It is important to note that as it relates to fixed delivery costs this block of the rate is only about 54% of the fixed demand related costs it is designed to recover.) For non-NEM customers the average use is 837 kWhs more than twice the average of NEM customers. This data alone is sufficient to demonstrate that NEM customers differ significantly from the residential class. While this one point is sufficient to demonstrate that the solar DG customers are not the same as full requirements customers, there is much more to the supporting data than claimed by witness Kobor.

Q. Witness Kobor states at pages 12 and 13 that "provided evidence that the Company's NEM and non-NEM customers have significantly different consumption patterns greater than the inevitable diversity in consumption within the residential and small commercial classes." Please comment on this claim.

A. First, it is an unfounded assertion and there is no evidence in the testimony of witness Kobor to support the claim. Second, with respect to the residential customers, these customers were full requirements customers before installing solar DG and their load shapes and load characteristics were reasonably the same as the average load shapes of other customers who consumed the same level of kWhs with some "inevitable diversity." After adding solar these customers are being billed for less than 40% of the kWhs and actually using more of the distribution system than they did as full requirements customers to deliver energy back to the system in low load periods. Third, despite the claim that I did not use any NEM customer data to reach my conclusions and that the Company did not use any NEM customer data for its conclusions, the bill frequency for NEM customers is an analysis of how the NEM customers actually used the system on a monthly basis. The use of actual solar PV output data in the service territory is also a reasonable, if conservative, basis for considering how the solar PV systems generate power and coupled with hourly load data on the residential class when that use is consumed on site and when it is delivered to the system. It is simply incorrect to say that the conclusions we reach are not based on information related to solar DG customers for UNS Electric.

The criticism that I have focused only on the costs and revenues for the test year is invalid as well. This is a rate case based on a test year. It is by its nature focused on test year revenue requirements and billing determinants. Longer term perspectives are handled in other ways such as the IRP filings.

Q. Please comment on the claim that "load reductions from seasonal and vacant homes and energy efficiency reductions far eclipse the reductions from DG."

A. This statement demonstrates a misunderstanding of the rate case process. Most utilities have seasonal and vacant homes every rate case. It would be only the growth of these categories between rate cases that would contribute to lower revenues and earnings. It is important also to understand that lost revenues between rate cases all come out of earnings and ultimately get transferred to other customers in the next rate case when rates are reset. There is no evidence to show that these issues are new or growing while the solar DG issue is growing and in any event is a much larger impact on revenues than seasonal and vacant homes. Witness Kobor simply does not understand the impact of solar DG as compared to other factors that are in every rate case and accounted for as part of costs and revenues in each case.

VIII. SUMMARY AND RECOMMENDATIONS

Q. Please summarize your rejoinder.

A. I show that the RAP article that several witnesses cite as a basis for rejecting demand rates is defective in a number of regards. As a result, residential demand rates should become the standard since the compromise that required volumetric only rates is no longer necessary. I show that the minimum system is a necessary component of cost of service in order to reflect cost causation. I show that the basic customer method coupled with NCP allocation of all distribution plant under allocates costs to residential customers and over allocates costs to larger customers. I show that the claims of superiority of a two-part TOU over demand rates cannot be proved and that such rates suffer from the defect that energy consumption is not a good measure of the various capacity components of costs.

I show that the minimum bill is inferior to a cost-based customer charge for recovery of fixed costs. I demonstrate that witnesses who believe that customers will have extremely large demands based on connected load do not understand how demand will be measured and have grossly overstated the impact of appliances on billing demand. Finally, I show that the purported evidence that solar DG customers are the same as full requirements customers results from misuse of the data relied on to conclude the customers are the same.

Q. Based on the testimony that has been filed, what recommendations would you make related to rates?

A. I recommend that the residential rates be designed initially as the proposed transition rates and the Commission approve the UNS proposed three part rates including TOU energy charges. I recognize that these rates are still a compromise and will need to be further modified over time to more closely match cost causation. Nevertheless moving to demand rates is a positive improvement over two-part rates. It is necessary to begin a transition and this is a reasonable starting point to have more efficient and just and reasonable rates for a 21st century utility.

Q. Does this conclude your Testimony?

A. Yes, it does.

Exhibit HEO-1

TABLE 11. ILLUSTRATIVE SUMMARY OF ASSIGNMENT OF FUNCTIONAL COST ELEMENTS TO PARAMETRIC COMPONENTS OF COST-TO-SERVE OF FOUR GENERAL CLASSES OF SERVICE

	"Customer" Component				"Customer Demand" Component				"Class Peak or Diversified Demand" Component				"Energy" Component			
	Mfg. & Nonmfg.			Res.	Mfg. & Nonmfg.			Res.	Mfg. & Nonmfg.			Res.	Mfg. & Nonmfg.			Res.
	HT	PD	Sec.	Sec.	HT	PD	Sec.	Sec.	HT	PD	Sec.	Sec.	HT	PD	Sec.	Sec.
Production system	–	–	–	–	–	–	–	–	X	X	X	X	X	X	X	X
Bulk transmission system	–	–	–	–	–	–	–	–	X	X	X	X	–	–	–	–
Distribution system																
High Tension distribution (Substations & lines)	–	–	–	–	X	–	–	–	–	X	X	X	–	–	–	–
Primary voltage distribution																
Substations	–	–	–	–	–	–	–	–	–	X	X	X	–	–	–	–
Capacitors	–	–	–	–	–	–	–	–	–	X	X	X	–	–	–	–
Feeders	–	–	–	–	–	X	–	–	–	–	X	X	–	–	–	–
Branches	–	X	X	X	–	–	X	X	–	–	–	–	–	–	–	–
Secondary voltage distribution																
Transformers	–	–	X	X	–	–	X	X	–	–	X	X	–	–	–	–
Capacitors	–	–	–	–	–	–	–	–	–	–	X	X	–	–	–	–
Mains	–	–	X	X	–	–	–	–	–	–	–	–	–	–	–	–
Service conductors	X	X	X	X	–	–	–	–	–	–	–	–	–	–	–	–
Metering and control system	X	X	X	X	–	–	–	–	–	–	–	–	–	–	–	–
Work on consumers' premises	X	X	X	X	–	–	–	–	–	–	–	–	–	–	–	–
Customers' accounting	X	X	X	X	–	–	–	–	–	–	–	–	–	–	–	–
Sales promotion	X	X	X	X	X	X	X	–	–	–	–	–	–	–	–	–
General administrative:																
General plant (carrying charges)	←(at fixed rate per dollar of foregoing plant)→															
General & administrative expenses	← at fixed rate per dollar of direct expenses (excluding fuel, energy purchases, and fixed charges) →															
Total cost-to-serve per unit of the parameter as at meters	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X

Note: Functional costs include expenses and carrying charges on investment in plant and working capital.

Sheehan Testimony Exhibit

Comparison of PPFAC Rate versus PPFAC Percentage Rate

Original Average Cost of Fuel	5.30 ¢/kWh
New Average Cost of Fuel	5.83 ¢/kWh
PPFAC Rate	0.53 ¢/kWh
PPFAC % Rate (1)	10%

	Test Year Base Fuel Rate	(2) Current PPFAC Rate	Resulting Increase	(3) Proposed PPFAC % Rate	Resulting Increase
Residential	5.40 ¢/kWh	5.93 ¢/kWh	9.81%	5.94 ¢/kWh	10.00%
General Service	5.30 ¢/kWh	5.83 ¢/kWh	10.00%	5.83 ¢/kWh	10.00%
CARES	4.30 ¢/kWh	4.83 ¢/kWh	12.33%	4.73 ¢/kWh	10.00%
Large Power	4.50 ¢/kWh	5.03 ¢/kWh	11.78%	4.95 ¢/kWh	10.00%

(1) PPFAC % Rate = New Average Cost of Fuel / Original Cost of Fuel - 1

(2) Add PFFAC Rate (0.53¢/kWh) to Base Fuel Rate

(3) Multiply Base Fuel Rate (1+PPFAC % Rate) (10%)

EXHIBIT

UNS E-36

~~ADMITTED~~

Regulatory Research Associates
REGULATORY FOCUS

RRA Topical Special Report October 2, 2015

ADJUSTMENT CLAUSES
~ A State-by-State Overview ~

The electric and natural gas utilities' use of adjustment clauses to recover variations in certain costs outside of the traditional rate case process has its origins in the 1973 Arab oil embargo, when fuel costs skyrocketed, leaving the utilities with no way to recover the increased costs in a timely manner. At that time, the only remedy for the utilities was to file a rate case; however, rate proceedings frequently took more than a year to litigate, while fuel prices climbed more rapidly than the utilities could obtain rate recognition of the increased costs. Certain jurisdictions permitted the utilities to have more than one rate case pending simultaneously; however, most did not. During these years, utility earnings were under considerable pressure, a situation that prompted certain jurisdictions to establish a more constructive framework to allow more timely recovery of cost increases that were beyond the control of the utilities.

The result was the creation of the fuel adjustment clause (FAC), essentially a single-issue ratemaking process, whereby a utility is permitted to implement periodic rate adjustments to reflect changes in its cost of fuel. The utility is generally authorized to defer incremental variations in its fuel costs to offset any effect on earnings from the variation in the cost. The deferred amount is then recovered from, or refunded to, ratepayers in the next FAC rate adjustment. In some circumstances, the FAC includes a forward-looking component that is subject to true-up provisions.

Over the ensuing years, the use of adjustment clauses expanded greatly. Adjustment clauses are generally reserved for expenses that are outside the control of the utility or are required by law or rule. In addition to fuel costs, most jurisdictions allow the utilities' purchased power expense to be included in the FAC. Some jurisdictions have approved the use of adjustment clauses for environmental compliance costs, conservation costs, or to pass through to customers the margins that the company receives from selling excess power or pipeline capacity in the open market (off-system sales). Some jurisdictions also allow expenses related to renewable energy to be recovered through a separate charge, and others permit the costs associated with the construction of new generation capacity or delivery infrastructure to be reflected in rates through an adjustment clause.

Another type of adjustment clause, a decoupling mechanism, enables utilities to offset the effect on revenues of unexpected sales reductions caused by energy efficiency programs, deviations from "normal" temperature patterns, or economic conditions in their territories. RRA considers a decoupling mechanism that adjusts for all three of these factors to be a "full" decoupling mechanism.

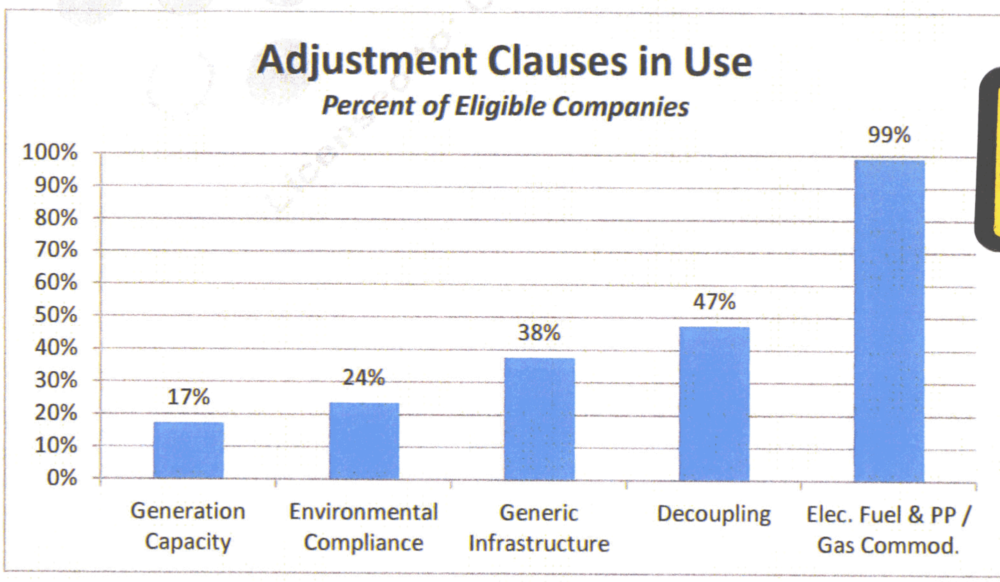


EXHIBIT
UNSE-37
admitted

Full and partial decoupling mechanisms included in total. Electric utilities operating in restructured electric markets included in total since they are not at risk of absorbing fuel-related losses.

A defining characteristic of an adjustment clause is that it effectively shifts the risk associated with recovery of the expense in question from shareholders to customers, because if the clause operates as designed, the company is able to change its rates to recover its costs on a current basis, without any negative effect on the bottom line and without the expense and delay that accompanies a rate case filing. This report does not address surcharges that have been approved to enable the utility to recover specific one-time items (e.g., excess storm restoration costs incurred in a given year), because under that scenario, the utility is recovering a fixed amount, that has already been incurred, over a defined period of time. This report also does not include expense trackers, which provide for the deferral of variations in certain costs for potential recovery at a future time, when the commission will consider the net accumulated balance for inclusion in rates. Although an expense tracker is designed to keep the utility's earnings whole, rates, and accordingly cash flows, do not change on a current basis. Expense trackers are sometimes authorized to account for variations in pension-related costs. Although there are similarities between each of these types of ratemaking provisions, only adjustment clauses allow rates to change on an expedited basis in accordance with cost changes.

This report covers the key adjustment clauses used by the largest electric and gas utilities in the 53 jurisdictions covered by RRA. The accompanying table includes footnotes (denoted by "✓*" or "--*"), beginning on page 14, only where a clarification regarding the specific adjustment clause is necessary. Further details concerning the adjustment clauses included in this report can be found in each of RRA's Commission Profiles. As indicated in the table, all of these jurisdictions employ some type of adjustment clause, with fuel/purchased power clauses being the most prevalent. Virtually all electric and gas utilities are permitted to adjust rates, outside of a base rate case, for variations in fuel/purchased power expenses, with the exception being PacifiCorp (electric) in Washington. We note that roughly two-thirds of all utility commissions permit the use of, or are considering the use of, an adjustment clause for new capital investment. In addition, some form of decoupling is in place in the vast majority of the jurisdictions. Roughly one-third of all jurisdictions have adjustment clauses in place to reflect changes in the costs associated with the utilities' participation in regional transmission organizations.

Regulatory Agency Abbreviations

ACC	- Arizona Corporation Commission
ARC	- Alaska Regulatory Commission
BPU	- Board of Public Utilities (New Jersey)
DPU	- Department of Public Utilities (Massachusetts)
ICC	- Illinois Commerce Commission
IUB	- Iowa Utilities Board
KCC	- Kansas Corporation Commission
NCUC	- North Carolina Utilities Commission
NOCC	- New Orleans City Council
OCC	- Oklahoma Corporation Commission
PRC	- Public Regulation Commission (New Mexico)
PSB	- Public Service Board (Vermont)
PSC	- Public Service Commission
PUC	- Public Utility(ies) Commission
PURA	- Public Utilities Regulatory Authority (Connecticut)
RRC	- Railroad Commission (Texas)
SCC	- State Corporation Commission (Virginia)
TRA	- Tennessee Regulatory Authority
URC	- Utility Regulatory Commission (Indiana)
WUTC	- Washington Utilities and Transportation Commission

Russell Ernst Lillian Federico John George Dennis Sperduto
Jim Davis Lisa Fontanella Monica Hlinka

Use of adjustment clauses (as of Oct. 2, 2015)

State/ Company	Ultimate Parent Ticker	Type of Service	Electric Fuel/ Gas Commodity/ Purch. Power	Conserv. Program Expense	Decoupling: Full	Decoupling: Partial	Renewables Expense	Environmental Compliance	New Capital: Generation Capacity	New Capital: Generic Infrastructure	RTO-Related Transmission Expense	Other
			Type of Adjustment Clause									
ALABAMA												
Alabama Power	SO	Elec.	✓*	–	–	–	–	✓*	✓*	–	–	✓*
Alabama Gas	LG	Gas	✓*	–	–	✓*	–	–	–	–	–	✓*
Mobile Gas	SRE	Gas	✓*	–	–	✓*	–	–	–	–	–	✓*
ALASKA												
Alaska Electric Light & Power	AVA	Elec.	✓	–	–	–	–	–	–	–	–	–
Enstar Natural Gas	–	Gas	✓	–	–	–	–	–	–	–	–	–
ARIZONA												
Arizona Public Service	PNW	Elec.	✓	✓	–	✓*	✓	✓	✓*	–	✓	✓*
Southwest Gas	SWX	Gas	✓	✓	✓*	–	–	–	–	–	–	✓*
Tucson Electric Power	–	Elec.	✓	✓	–	✓*	✓	✓	–	–	–	✓*
UNS Electric	–	Elec.	✓	✓	–	✓*	✓	–	–	–	✓	✓*
UNS Gas	–	Gas	✓	✓	–	✓*	–	–	–	–	–	✓*
ARKANSAS												
Arkansas Oklahoma Gas	–	Gas	✓	✓	✓	–	–	–	–	✓	–	✓*
CenterPoint Energy Resources	CNP	Gas	✓	✓	✓	–	–	–	–	✓	–	✓*
Entergy Arkansas	ETR	Elec.	✓	✓	–	✓*	–	–	✓*	✓*	✓	✓*
Oklahoma Gas & Electric	OGE	Elec.	✓	✓	–	✓*	✓	–	✓	–	✓	✓*
SourceGas Arkansas	–	Gas	✓	✓	✓	–	–	–	–	✓	–	✓*
Southwestern Electric Power	AEP	Elec.	✓	✓	–	✓*	–	–	✓	–	–	✓*
CALIFORNIA												
Pacific Gas & Electric	PCG	Elec.	✓	–	✓	–	–	–	–	–	–	–
Pacific Gas & Electric	PCG	Gas	✓	–	✓	–	–	–	–	–	–	–
San Diego Gas & Electric	SRE	Elec.	✓	–	✓	–	–	–	–	–	–	–
San Diego Gas & Electric	SRE	Gas	✓	–	✓	–	–	–	–	–	–	–
Southern California Edison	EIX	Elec.	✓	–	✓	–	–	–	–	–	–	–
Southern California Gas	SRE	Gas	✓	–	✓	–	–	–	–	–	–	–
Southwest Gas	SWX	Gas	✓	–	✓	–	–	–	–	–	–	–
COLORADO												
Black Hills Colorado Electric	BKH	Elec.	✓	✓	–	–	✓	–*	✓*	✓*	–	✓*
Public Service Co. of Colorado	XEL	Elec.	✓	✓	–	–	✓	–*	–	✓*	–	✓*
Public Service Co. of Colorado	XEL	Gas	✓	✓	–	✓*	–	–	–	✓*	–	–
SourceGas Distribution	–	Gas	✓	✓	–	–	–	–	–	–	–	–

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Adjustment Clause: Electric Fuel/ Gas Commodity/ Purch. Power	Conserv. Program Expense	Decoupling: Full	Decoupling: Partial	Renewables Expense	Environmental Compliance	New Capital: Generation Capacity	New Capital: Generic Infrastructure	RTO-Related Transmission Expense	Other
CONNECTICUT												
Connecticut Lt. & Pwr.	ES	Elec.	–*	✓	✓*	–	–	–	–	–	✓	–
Conn. Natural Gas	UIL	Gas	✓	✓	✓*	–	–	–	–	✓*	–	–
Southern Conn. Gas	UIL	Gas	✓	✓	–*	–	–	–	–	✓*	–	–
United Illuminating	UIL	Elec.	–*	✓	✓*	–	–	–	–	–	✓	–
Yankee Gas Service	ES	Gas	✓	✓	–*	–	–	–	–	✓*	–	–
DELAWARE												
Chesapeake Utilities	CPK	Gas	✓	–	–	–	–	–	–	–	–	✓*
Delmarva Power & Light	POM	Elec.	–*	–	–	–	–	–	–	–	✓	–
Delmarva Power & Light	POM	Gas	✓	–	–	–	–	✓	–	–	–	–
DISTRICT OF COLUMBIA												
Potomac Electric Power	POM	Elec.	–*	–	–	✓*	✓*	–	–	✓*	–	✓*
Washington Gas Light	WGL	Gas	✓	–	–	–	–	–	–	✓*	–	✓*
FLORIDA												
Florida Power & Light	NEE	Elec.	✓	✓	–	–	–	✓	✓*	–	–	✓*
Duke Energy Florida	DUK	Elec.	✓	✓	–	–	–	✓	✓*	–	–	✓*
Florida Public Utilities	CPK	Elec.	✓	✓	–	–	–	✓	✓*	–	–	✓*
Florida Public Utilities	CPK	Gas	✓	✓	–	–	–	✓	–	✓*	–	✓*
Gulf Power	SO	Elec.	✓	✓	–	–	–	✓	✓*	–	–	✓*
Peoples Gas System	TE	Gas	✓	✓	–	–	–	✓	–	✓*	–	✓*
Pivotal Utility Holdings	GAS	Gas	✓	✓	–	–	–	✓	–	✓*	–	✓*
Tampa Electric	TE	Elec.	✓	✓	–	–	–	✓	✓*	–	–	✓*
GEORGIA												
Atlanta Gas Light	GAS	Gas	–*	–	–*	–	–	✓*	–	✓*	–	–
Georgia Power	SO	Elec.	✓	–	–	–	–	–	✓*	–	–	–
Liberty Utilities (Peach State Natural Gas)	–	Gas	✓*	–	✓*	–	–	–	–	–	–	–
HAWAII												
Hawaiian Electric	HE	Elec.	✓	✓	✓	–	✓	–	✓*	✓*	–	–
Hawaii Electric Light	HE	Elec.	✓	✓	✓	–	✓	–	✓*	✓*	–	–
Maui Electric	HE	Elec.	✓	✓	✓	–	✓	–	✓*	✓*	–	–
IDAHO												
Avista Corp.	AVA	Elec.	✓*	✓	–	–	–	–	–	–	–	–
Avista Corp.	AVA	Gas	✓	✓	–	–	–	–	–	–	–	–
Idaho Power	IDA	Elec.	✓*	✓	–	✓*	–	–	–	–	–	–
PacifiCorp	BRK.A	Elec.	✓*	✓	–	–	–	–	–	–	–	–

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Adjustment Clause: Electric Fuel/ Gas Commodity/ Purch. Power	Conserv. Program Expense	Decoupling: Full	Decoupling: Partial	Renewables Expense	Environmental Compliance	New Capital: Generation Capacity	New Capital: Generic Infrastructure	RTO-Related Transmission Expense	Other
ILLINOIS												
Ameren Illinois	AEE	Elec.	—*	✓	—	—	✓	✓*	—	—	✓	✓*
Ameren Illinois	AEE	Gas	✓	✓	—	—	—	✓*	—	✓*	—	✓*
Commonwealth Edison	EXC	Elec.	—*	✓	—	—	✓	✓*	—	—	✓	✓*
MidAmerican Energy	BRK.A	Elec.	✓	✓	—	—	✓	—	—	—	✓	✓*
MidAmerican Energy	BRK.A	Gas	✓	✓	—	—	—	—	—	—*	—	✓*
North Shore Gas	WEC	Gas	✓	✓	✓	—	—	✓*	—	—*	—	✓*
Northern Illinois Gas	GAS	Gas	✓	✓	—	—	—	✓*	—	✓*	—	✓*
Peoples Gas Light & Coke	WEC	Gas	✓	✓	✓	—	—	✓*	—	✓*	—	✓*
INDIANA												
Duke Energy Indiana	DUK	Elec.	✓	✓	—	✓*	✓	✓*	✓*	—	✓	✓*
Indiana Gas	VVC	Gas	✓	✓	✓*	—	—	—	—	✓*	—	✓*
Indiana Michigan Power	AEP	Elec.	✓	✓	—	✓*	—	✓*	—	—*	✓	✓*
Indianapolis Power & Light	AES	Elec.	✓	✓	—	✓*	✓	✓*	—	—*	—	—
Northern Indiana Public Service	NI	Elec.	✓	✓	—	✓*	✓	✓*	—	✓*	✓	✓*
Northern Indiana Public Service	NI	Gas	✓	✓	—	—	—	—	—	✓*	—	✓*
Southern Indiana Gas & Electric	VVC	Elec.	✓	✓	—	✓*	—	—*	—	—*	✓	✓*
Southern Indiana Gas & Electric	VVC	Gas	✓	✓	✓*	—	—	—	—	✓*	—	✓*
IOWA												
Black Hills Iowa Gas Utility	BKH	Gas	✓	✓	—	—	—	—	—	✓	—	✓*
Interstate Power & Light	LNT	Elec.	✓	✓	—	—	✓	✓*	—	—	✓	✓*
Interstate Power & Light	LNT	Gas	✓	✓	—	—	—	—	—	—	—	✓*
MidAmerican Energy	BRK.A	Elec.	✓	✓	—	—	✓	✓*	—	—	✓	✓*
MidAmerican Energy	BRK.A	Gas	✓	✓	—	—	—	—	—	—	—	✓*
KANSAS												
Atmos Energy	ATO	Gas	✓	—*	—	✓*	—	—	—	✓*	—	✓*
Black Hills/Kansas Gas Utility	BKH	Gas	✓	—*	—	✓*	—	—	—	✓*	—	✓*
Empire District Electric	EDE	Elec.	✓	✓	—	—	—	✓	—	—	—	✓*
Kansas City Power & Light	GXP	Elec.	✓	✓	—	—	—	—	—	—	✓	✓*
Kansas Gas & Electric	WR	Elec.	✓	✓	—	✓*	✓	✓	—	—	✓	✓*
Kansas Gas Service	OGS	Gas	✓	—*	—	✓*	—	—	—	✓*	—	✓*
Westar Energy	WR	Elec.	✓	✓	—	✓*	✓	✓	—	—	✓	✓*

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Adjustment Clause: Electric Fuel/ Gas Commodity/ Purch. Power	Conserv. Program Expense	Decoupling: Full	Decoupling: Partial	Renewables Expense	Environmental Compliance	New Capital: Generation Capacity	New Capital: Generic Infrastructure	RTO-Related Transmission Expense	Other
KENTUCKY												
Atmos Energy	ATO	Gas	✓	✓	–	✓*	–	–	–	✓*	–	✓*
Columbia Gas of Kentucky	NI	Gas	✓	✓	–	✓*	–	–	–	✓*	–	✓*
Delta Natural Gas	DGAS	Gas	✓	✓	–	✓*	–	–	–	✓*	–	✓*
Duke Energy Kentucky	DUK	Elec.	✓	✓	–	✓*	–	–	–	–	–	✓*
Duke Energy Kentucky	DUK	Gas	✓	✓	–	✓*	–	–	–	–	–	✓*
Kentucky Power	AEP	Elec.	✓	✓	–	✓*	–	✓*	✓*	–	–	✓*
Kentucky Utilities	PPL	Elec.	✓	✓	–	✓*	–	✓*	–	–	–	✓*
Louisville Gas & Electric	PPL	Elec.	✓	✓	–	✓*	–	✓*	–	–	–	✓*
Louisville Gas & Electric	PPL	Gas	✓	✓	–	✓*	–	–	–	✓*	–	✓*
LOUISIANA-NOCC												
Entergy New Orleans	ETR	Elec.	✓	✓	–	✓*	–	✓*	✓*	–	✓	✓*
Entergy New Orleans	ETR	Gas	✓	–	–	–	–	–	–	–	–	✓*
LOUISIANA PSC												
Atmos Energy	ATO	Gas	✓	–	–	✓*	–	–	–	✓*	–	–
CenterPoint Energy Resources (Arkla)	CNP	Gas	✓	–	–	✓*	–	–	–	–	–	–
Cleco Power	CNL	Elec.	✓	✓	–	✓*	–	✓*	–	–	–	✓*
Entergy Louisiana	ETR	Elec.	✓	✓	–	✓*	–	✓*	✓*	–	✓*	✓*
Entergy Louisiana	ETR	Gas	✓	–	–	✓*	–	–	–	✓*	–	–
Southwestern Electric Power	AEP	Elec.	✓	✓	–	✓*	–	✓*	–	–	–	✓*
MAINE												
Central Maine Power	–	Elec.	–*	–	✓*	–	–	–	–	–	–	✓*
Emera Maine	–	Elec.	–*	–	–	–	–	–	–	–	–	–
Maine Natural Gas	–	Gas	✓	–	–	–	–	–	–	–	–	–
Northern Utilities	UTL	Gas	✓	–	–	–	–	✓*	–	✓*	–	–
MARYLAND												
Baltimore Gas & Electric	EXC	Elec.	–*	✓*	✓	–	–	–	–	–	–	✓*
Baltimore Gas & Electric	EXC	Gas	✓	✓*	✓	–	–	–	–	✓*	–	✓*
Columbia Gas of Maryland	NI	Gas	✓	✓*	–	✓*	–	–	–	✓*	–	✓*
Delmarva Power & Light	POM	Elec.	–*	✓*	✓	–	–	–	–	✓*	–	–
Potomac Edison	FE	Elec.	–*	✓*	–	–	–	–	–	–	–	✓*
Potomac Electric Power	POM	Elec.	–*	✓*	✓	–	–	–	–	✓*	–	✓*
Washington Gas Light	WGL	Gas	✓	✓*	–	✓*	–	–	–	✓*	–	✓*

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Adjustment Clause: Electric Fuel/ Gas Commodity/ Purch. Power	Conserv. Program Expense	Decoupling: Full	Decoupling: Partial	Renewables Expense	Environmental Compliance	New Capital: Generation Capacity	New Capital: Generic Infrastructure	RTO-Related Transmission Expense	Other
MASSACHUSETTS												
Bay State Gas	NI	Gas	✓	✓*	✓	–	–	✓*	–	✓*	–	✓*
Berkshire Gas	UIL	Gas	✓	–	–	–	–	–	–	✓*	–	–
Boston Gas/Colonial Gas	–	Gas	✓	✓*	✓	–	–	✓*	–	✓*	–	✓*
Fitchburg Gas & Electric	UTL	Elec.	–*	✓*	✓	–	–	–	–	–	✓	✓*
Fitchburg Gas & Electric	UTL	Gas	✓	✓*	✓	–	–	✓*	–	✓*	–	✓*
Liberty Utilities (New England Gas)	–	Gas	✓	✓*	✓	–	–	✓*	–	✓*	–	✓*
Massachusetts Electric	–	Elec.	–*	✓*	✓	–	✓*	–	✓*	✓*	✓	✓*
NSTAR Electric	ES	Elec.	–*	✓*	–	–	–	–	–	–	✓	✓*
NSTAR Gas	ES	Gas	✓	✓*	–	–	–	✓*	–	–*	–	✓*
Western Mass. Electric	ES	Elec.	–*	✓*	✓	–	✓*	–	✓*	–	✓	✓*
MICHIGAN												
Consumers Energy	CMS	Elec.	✓	✓	–*	–	✓	–	–	–	✓*	–
Consumers Energy	CMS	Gas	✓	✓	–	–*	–	–	–	–	–	–
DTE Electric	DTE	Elec.	✓	✓	–*	–	✓	–	–	–	✓*	–
DTE Gas	DTE	Gas	✓	✓	–	✓*	–	–	–	✓*	–	–
Indiana Michigan Power	AEP	Elec.	✓	✓	–*	–	✓	–	–	–	–	–
Michigan Gas Utilities	WEC	Gas	✓	✓	–	–*	–	–	–	–	–	–
SEMCO Energy Gas	–	Gas	✓	✓	–	–	–	–	–	–	–	–
Upper Peninsula Power	–	Elec.	✓	✓	–*	–	✓	–	–	–	✓*	–
Wisconsin Electric Power	WEC	Elec.	✓	✓	–*	–	✓	–	–	–	–	–
MINNESOTA												
Minnesota Power	ALE	Elec.	✓	✓	–	–	✓	✓	–	–	✓	–
CenterPoint Energy Resources	CNP	Gas	✓	✓	✓*	–	–	–	–	–	–	–
Minnesota Energy Resources	WEC	Gas	✓	✓	✓*	–	–	–	–	–	–	–
Northern States Power-Minnesota	XEL	Elec.	✓	✓	–*	–	✓	✓	–	–	✓	–
Northern States Power-Minnesota	XEL	Gas	✓	✓	–	–	–	–	–	✓*	–	–
Otter Tail Power	OTTR	Elec.	✓	✓	–	–	✓	✓	–	–	✓	–
MISSISSIPPI												
Atmos Energy	ATO	Gas	✓	–	–	✓*	–	–	–	–	–	–
Entergy Mississippi	ETR	Elec.	✓	✓	–	✓*	–	✓*	✓*	–	✓	✓*
Mississippi Power	SO	Elec.	✓	✓	–	✓*	–	✓*	–	–	–	✓*

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Adjustment Clause: Electric Fuel/ Gas Commodity/ Purch. Power	Conserv. Program Expense	Decoupling: Full	Decoupling: Partial	Renewables Expense	Environmental Compliance	New Capital: Generation Capacity	New Capital: Generic Infrastructure	RTO-Related Transmission Expense	Other
MISSOURI												
Empire District Electric	EDE	Elec.	✓	–	–	–	–*	✓*	–	–	–	✓*
Empire District Gas	EDE	Gas	✓	–	–	–*	–	–	–	–	–	✓*
Kansas City Power & Light	GXP	Elec.	✓	✓*	–	✓*	–*	–*	–	–	–	✓*
KCP&L Greater Missouri Operations	GXP	Elec.	✓	–	–	✓*	✓*	✓*	–	–	–	✓*
Laclede Gas	LG	Gas	✓	–	–	–*	–	–	–	✓*	–	✓*
Liberty Utilities (Midstates Natural Gas)	–	Gas	✓	–	–	–*	–	–	–	✓*	–	✓*
Missouri Gas Energy	LG	Gas	✓	–	–	–*	–	–	–	✓*	–	✓*
Union Electric	AEE	Elec.	✓	✓*	–	✓*	–*	✓*	–	–	–	✓*
Union Electric	AEE	Gas	✓	–	–	–*	–	–	–	✓*	–	✓*
MONTANA												
MDU Resources	MDU	Elec.	✓*	✓	–	–	–	–	–	–	–	✓*
MDU Resources	MDU	Gas	✓	✓	–	✓*	–	–	–	–	–	–
NorthWestern Corp.	NWE	Elec.	✓*	✓	–	✓*	–	–	–	–	–	✓*
NorthWestern Corp.	NWE	Gas	✓	✓	–	–	–	–	–	–	–	✓*
NEBRASKA												
Black Hills Nebraska Gas Utility	BKH	Gas	✓	–	–	–	–	–	–	✓*	–	✓*
Northwestern Energy	NWE	Gas	✓	–	–	–	–	–	–	–*	–	✓*
SourceGas Distribution	–	Gas	✓	–	–	–	–	–	–	✓*	–	✓*
NEVADA												
Nevada Power	BRK.A	Elec.	✓	✓	–	✓*	–	–	–	–	–	–
Sierra Pacific Power	BRK.A	Elec.	✓	✓	–	✓*	–	–	–	–	–	–
Sierra Pacific Power	BRK.A	Gas	✓	–	–	–	–	–	–	–*	–	–
Southwest Gas	SWX	Gas	✓	–	✓*	–	–	–	–	✓*	–	✓*
NEW HAMPSHIRE												
Liberty Utilities (EnergyNorth Natural Gas)	–	Gas	✓	–	–	–	–	–	–	✓*	–	–
Liberty Utilities (Granite State Electric)	–	Elec.	–*	–	–	–	–	–	–	✓*	–	–
Northern Utilities	UTL	Gas	✓	–	–	–	–	–	–	–	–	–
Public Service Co. of New Hampshire	ES	Elec.	✓*	–	–	–	–	–	–	✓*	✓	–
Unitil Energy Systems	UTL	Elec.	–*	–	–	–	–	–	–	✓*	–	–

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Adjustment Clause: Electric Fuel/ Gas Commodity/ Purch. Power	Conserv. Program Expense	Decoupling: Full	Decoupling: Partial	Renewables Expense	Environmental Compliance	New Capital: Generation Capacity	New Capital: Generic Infrastructure	RTO-Related Transmission Expense	Other
NEW JERSEY												
Atlantic City Electric	POM	Elec.	–*	✓	–	–	✓	–	–	–	–	✓*
Jersey Central Power & Light	FE	Elec.	–*	✓	–	–	✓	–	–	–*	–	✓*
New Jersey Natural Gas	NJR	Gas	✓	✓	✓*	–	–	✓*	–	✓*	–	✓*
Pivotal Utility Holdings	GAS	Gas	✓	✓	–	✓*	–	✓*	–	✓*	–	✓*
Public Service Electric & Gas	PEG	Elec.	–*	✓	–	–	✓	–	–	✓*	–	✓*
Public Service Electric & Gas	PEG	Gas	✓	✓	–	✓*	–	✓*	–	✓*	–	✓*
Rockland Electric	ED	Elec.	–*	✓	–	–	✓	–	–	–	–	✓*
South Jersey Gas	SJI	Gas	✓	✓	✓*	–	–	✓*	–	✓*	–	✓*
NEW MEXICO												
El Paso Electric	EE	Elec.	✓	✓	–	–	–	–	–		–	✓*
New Mexico Gas	TE	Gas	✓	✓	–	–	–	–	–		–	✓*
Public Service Co. of New Mexico	PNM	Elec.	✓	✓	–	–	✓	✓*	–		–	✓*
Southwestern Public Service	XEL	Elec.	✓	✓	–	–	✓	–	–		–	✓*
NEW YORK												
Brooklyn Union Gas	–	Gas	✓	–	✓	–	–	–	–	–	–	–
Central Hudson Gas & Electric	–	Elec.	–*	–	✓	–	✓	–	–	–	–	–
Central Hudson Gas & Electric	–	Gas	✓	–	✓	–	–	–	–	–	–	–
Consolidated Edison of New York	ED	Elec.	–*	–	✓	–	✓	–	–	–	–	–
Consolidated Edison of New York	ED	Gas	✓	–	✓	–	–	–	–	–	–	–
KeySpan Gas East	–	Gas	✓	–	✓	–	–	–	–	–	–	–
National Fuel Gas Distribution	NFG	Gas	✓	–	✓	–	–	–	–	–	–	–
New York State Electric & Gas	–	Elec.	–*	–	✓	–	✓	–	–	–	–	–
New York State Electric & Gas	–	Gas	✓	–	✓	–	–	–	–	–	–	–
Niagara Mohawk Power	–	Elec.	–*	–	✓	–	✓	–	–	–	–	–
Niagara Mohawk Power	–	Gas	✓	–	✓	–	–	–	–	–	–	–
Orange & Rockland Utilities	ED	Elec.	–*	–	✓	–	✓	–	–	–	–	–
Orange & Rockland Utilities	ED	Gas	✓	–	✓	–	–	–	–	–	–	–
Rochester Gas & Electric	–	Elec.	–*	–	✓	–	✓	–	–	–	–	–
Rochester Gas & Electric	–	Gas	✓	–	✓	–	–	–	–	–	–	–
NORTH CAROLINA												
Duke Energy Carolinas	DUK	Elec.	✓	✓	–	–*	✓*	✓*	–	–	–	–
Duke Energy Progress	DUK	Elec.	✓	✓	–	–*	✓*	✓*	–	–	–	–
Piedmont Natural Gas	PNY	Gas	✓	–	✓*	–	–	–	–	✓*	–	–
Public Service Co. of North Carolina	SCG	Gas	✓	–	✓*	–	–	–	–	–	–	–
Virginia Electric & Power	D	Elec.	✓	✓	–	–*	✓*	✓*	–	–	–	–

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Adjustment Clause: Electric Fuel/ Gas Commodity/ Purch. Power	Conserv. Program Expense	Decoupling: Full	Decoupling: Partial	Renewables Expense	Environmental Compliance	New Capital: Generation Capacity	New Capital: Generic Infrastructure	RTO-Related Transmission Expense	Other
NORTH DAKOTA												
MDU Resources	MDU	Elec.	✓	–	–	–	–	✓*	✓*	✓*	–	–
MDU Resources	MDU	Gas	✓	–	–	✓*	–	–	–	–	–	–
Northern States Power-Minnesota	XEL	Elec.	✓	–	–	–	✓	✓*	–	✓*	–	✓*
Northern States Power-Minnesota	XEL	Gas	✓	–	–*	–	–	–	–	–	–	–
Otter Tail Power	OTTR	Elec.	✓	–	–	–	✓	✓*	–	✓*	–	✓*
OHIO												
Cleveland Electric Illuminating	FE	Elec.	–*	✓*	–	✓*	✓	–	–	✓*	✓	✓*
Columbia Gas of Ohio	NI	Gas	–*	✓	–*	–	–	–	–	✓*	–	✓*
Dayton Power & Light	AES	Elec.	–*	✓*	–	✓*	–	–	–	✓*	✓	✓*
Duke Energy Ohio	DUK	Elec.	–*	✓*	–	✓*	–	–	–	✓*	✓	✓*
Duke Energy Ohio	DUK	Gas	✓	–	–*	–	–	–	–	✓*	–	✓*
East Ohio Gas	D	Gas	–*	–	–*	–	–	–	–	✓*	–	✓*
Ohio Edison	FE	Elec.	–*	✓*	–	✓*	✓	–	–	✓*	✓	✓*
Ohio Power	AEP	Elec.	–*	✓*	–	✓*	✓	–	–	✓*	✓	✓*
Toledo Edison	FE	Elec.	–*	✓*	–	✓*	✓	–	–	✓*	✓	✓*
Vectren Energy Delivery of Ohio	VVC	Gas	–*	–	–*	–	–	–	–	✓*	–	✓*
OKLAHOMA												
CenterPoint Energy Resources	CNP	Gas	✓	✓*	–	✓*	–	–	–	–	–	✓*
Oklahoma Gas & Electric	OGE	Elec.	✓	✓*	–	✓*	–	✓*	✓*	✓*	✓	✓*
Oklahoma Natural Gas	OGS	Gas	✓	✓*	–	✓*	–	–	–	–	–	✓*
Public Service Oklahoma	AEP	Elec.	✓	✓*	–	✓*	–	–*	–	✓*	✓	✓*
OREGON												
Avista Corp.	AVA	Gas	✓	–	–	–	–	–	–	–	–	–
Cascade Natural Gas	MDU	Gas	✓	–	–	✓*	–	–	–	–	–	–
Idaho Power	IDA	Elec.	✓*	–	–	–	✓*	–	–	–	–	–
Northwest Natural Gas	NWN	Gas	✓	–	–	✓*	–	✓*	–	–*	–	–
PacifiCorp	BRK.A	Elec.	✓*	–	–	–	✓*	–	–	–	–	–
Portland General Electric	POR	Elec.	✓*	–	–	✓*	✓*	–	–	–	–	–

State/ Company	Ultimate Parent Ticker	Type of Service	Type of Adjustment Clause: Electric Fuel/ Gas Commodity/ Purch. Power	Conserv. Program Expense	Decoupling: Full	Decoupling: Partial	Renewables Expense	Environmental Compliance	New Capital: Generation Capacity	New Capital: Generic Infrastructure	RTO-Related Transmission Expense	Other
PENNSYLVANIA												
Columbia Gas of Pennsylvania	NI	Gas	✓	✓	—	✓*	—	—	—	✓*	—	✓*
Duquesne Light	—	Elec.	—*	✓	—	—	—*	—	—	—*	✓	✓*
Equitable Gas	—	Gas	✓	✓	—	—	—	—	—	✓*	—	✓*
Metropolitan Edison	FE	Elec.	—*	✓	—	—	—*	—	—	—*	✓	✓*
National Fuel Gas Distribution	NFG	Gas	✓	✓	—	—	—	—	—	—*	—	✓*
PECO Energy	EXC	Elec.	—*	✓	—	—	—*	—	—	—*	—	✓*
PECO Energy	EXC	Gas	✓	✓	—	—	—	—	—	✓*	—	✓*
Pennsylvania Electric	FE	Elec.	—*	✓	—	—	—*	—	—	—*	✓	✓*
Pennsylvania Power	FE	Elec.	—*	✓	—	—	—*	—	—	—*	—	✓*
Peoples Natural Gas	—	Gas	✓	✓	—	—	—	—	—	✓*	—	✓*
PPL Electric Utilities	PPL	Elec.	—*	✓	—	—	—*	—	—	✓*	✓	✓*
UGI Central Penn Gas	UGI	Gas	✓	✓	—	—	—	—	—	✓*	—	✓*
UGI Penn Natural Gas	UGI	Gas	✓	✓	—	—	—	—	—	✓*	—	✓*
West Penn Power	FE	Elec.	—*	✓	—	—	—*	—	—	—*	—	✓*
UGI Utilities	UGI	Elec.	—*	✓	—	—	—*	—	—	—*	—	✓*
UGI Utilities	UGI	Gas	✓	✓	—	—	—	—	—	—*	—	✓*
RHODE ISLAND												
Narragansett Electric	—	Elec.	—*	—	✓*	—	—	—	—	✓*	—	✓*
Narragansett Electric	—	Gas	✓	✓*	✓*	—	—	✓*	—	✓*	—	✓*
SOUTH CAROLINA												
Carolina Power & Light	DUK	Elec.	✓	—	—	—	—	✓*	—*	—	—	—
Duke Energy Carolinas	DUK	Elec.	✓	—	—	—	—	✓*	—*	—	—	—
Piedmont Natural Gas	PNY	Gas	✓	—	—	✓*	—	—	—	—	—	—
South Carolina Electric & Gas	SCG	Elec.	✓	—	—	—	—	✓*	✓*	—	—	—
South Carolina Electric & Gas	SCG	Gas	✓	—	—	✓*	—	—	—	—	—	—
SOUTH DAKOTA												
Black Hills Power	BKH	Elec.	✓	✓*	—	✓*	—	✓	—	—	✓	✓*
Northern States Power-Minnesota	XEL	Elec.	✓	✓*	—	✓*	—	✓	✓*	✓*	—	✓*
NorthWestern Corp.	NWE	Elec.	✓	✓	—	—	—	—	—	—	—	—
TENNESSEE												
Atmos Energy	ATO	Gas	✓	—	—	✓*	—	✓	—	—	—	✓*
Chattanooga Gas	GAS	Gas	✓	—	✓*	—	—	—	—	—	—	✓*
Kingsport Power	AEP	Elec.	✓	—	—	—	—	—	—	—	—	—
Piedmont Natural Gas	PNY	Gas	✓	—	—	✓*	—	—	—	✓	—	✓*

State/ Company	Ultimate Parent Ticker	Type of Service	Electric Fuel/ Gas Commodity/ Purch. Power	Conserv. Program Expense	Decoupling Full	Decoupling Partial	Renewables Expense	Environmental Compliance	New Capital Generation Capacity	New Capital Generic Infrastructure	RTO-Related Transmission Expense	Other
TEXAS PUC												
AEP Texas Central	AEP	Elec.	–*	✓*	–	–	–	–	–	✓*	✓*	–
AEP Texas North	AEP	Elec.	–*	✓*	–	–	–	–	–	✓*	✓*	–
CenterPoint Energy Houston Electric	CNP	Elec.	–*	✓*	–	–	–	–	–	✓*	✓*	✓*
Cross Texas Transmission	–	Elec.	–	–	–	–	–	–	–	✓*	–	–
El Paso Electric	EE	Elec.	✓*	✓*	–	–	–	–	–	✓*	–	✓*
Electric Transmission of Texas	BRK.A/AEF	Elec.	–	–	–	–	–	–	–	✓*	–	–
Entergy Texas	ETR	Elec.	✓*	✓*	–	–	–	–	–	✓*	–	✓*
Lone Star Transmission	NEE	Elec.	–	–	–	–	–	–	–	✓*	–	–
Oncor Electric Delivery	–	Elec.	–*	✓*	–	–	–	–	–	✓*	✓*	–
Southwestern Electric Power	AEP	Elec.	✓*	✓*	–	–	–	–	–	✓*	–	–
Southwestern Public Service	XEL	Elec.	✓*	✓*	–	–	–	–	–	✓*	✓*	✓*
Texas-New Mexico Power	PNM	Elec.	–*	✓*	–	–	–	–	–	✓*	✓*	✓*
Wind Energy Transmission of Texas	–	Elec.	–	–	–	–	–	–	–	✓*	–	–
TEXAS RRC												
Atmos Energy	ATO	Gas	✓*	–	–	✓*	–	–	–	✓*	–	✓*
CenterPoint Energy Resources	CNP	Gas	–*	–	–	–	–	–	–	✓*	–	–
Texas Gas Service	OGS	Gas	✓*	–	–	✓*	–	–	–	✓*	–	–
UTAH												
PacifiCorp	BRK.A	Elec.	✓	✓	–	–	✓*	–	–		–	–
Questar	STR	Gas	✓	✓	✓*	–	–	–	–	✓*	–	✓*
VERMONT												
Green Mountain Power	–	Elec.	✓	–	–*	–	–	–	–	–	–	–
Vermont Gas Systems	–	Gas	✓	–	–*	–	–	–	–	–	–	–
VIRGINIA												
Appalachian Power	AEP	Elec.	✓*	✓*	–	–	✓	✓*	✓*	–*	✓	✓*
Columbia Gas of Virginia	NI	Gas	✓	✓*	–	✓*	–	–	–	✓*	–	✓*
Kentucky Utilities	PPL	Elec.	✓*	–*	–	–	–	–	–*	–*	–	–
Virginia Electric & Power	D	Elec.	✓*	✓*	–	–	–	✓*	✓*	–*	✓	✓*
Virginia Natural Gas	GAS	Gas	✓	–*	–	✓*	–	–	–	✓*	–	–
Washington Gas	WGL	Gas	✓	–*	–	✓*	–	–	–	✓*	–	✓*

			Type of Adjustment Clause									
									New Capital			
State/ Company	Ultimate Parent Ticker	Type of Service	Electric Fuel/ Gas Commodity/ Purch. Power	Conserv. Program Expense	Decoupling Full	Decoupling Partial	Renewables Expense	Environmental Compliance	Generation Capacity	Generic Infrastructure	RTO-Related Transmission Expense	Other
WASHINGTON												
Avista Corp.	AVA	Elec.	✓*	–	✓*	–	–	–	–	–	–	–
Avista Corp.	AVA	Gas	✓	–	✓*	–	–	–	–	–*	–	–
Cascade Natural Gas	MDU	Gas	✓	–	–	–	–	–	–	✓*	–	–
Northwest Natural Gas	NWN	Gas	✓	–	–	–	–	–	–	–*	–	–
PacifiCorp	BRK.A	Elec.	–	–	–	–	–	–	–	–	–	–
Puget Sound Energy	–	Elec.	✓*	–	–	✓*	–	–	–	–	–	–
Puget Sound Energy	–	Gas	✓	–	–	✓*	–	–	–	✓*	–	–
WEST VIRGINIA												
Appalachian Power	AEP	Elec.	✓	–	–	–	–	–*	–*	–*	✓	✓*
Hope Gas	D	Gas	✓	–	–	–	–	–	–	–	–	✓*
Monongahela Power	FE	Elec.	✓	–	–	–	–	–	–	–	–	✓*
Mountaineer Gas	–	Gas	✓	–	–	–	–	–	–	–	–	✓*
Potomac Edison	FE	Elec.	✓	–	–	–	–	–	–	–	–	✓*
Wheeling Power	AEP	Elec.	✓	–	–	–	–	–*	–*	–*	✓	✓*
WISCONSIN												
Madison Gas & Electric	MGEE	Elec.	✓*	–	–	–	–	–	–*	–*	–	✓*
Madison Gas & Electric	MGEE	Gas	✓	–	–	–	–	–	–*	–*	–	✓*
Northern States Power-Wisconsin	XEL	Elec.	✓*	–	–	–	–	–	–*	–*	–	✓*
Northern States Power-Wisconsin	XEL	Gas	✓	–	–	–	–	–	–*	–*	–	✓*
Wisconsin Electric Power	WEC	Elec.	✓*	–	–	–	–	–	–*	–*	–	✓*
Wisconsin Electric Power	WEC	Gas	✓	–	–	–	–	–	–*	–*	–	✓*
Wisconsin Gas	WEC	Gas	✓	–	–	–	–	–	–*	–*	–	✓*
Wisconsin Power & Light	LNT	Elec.	✓*	–	–	–	–	–	–*	–*	–	✓*
Wisconsin Power & Light	LNT	Gas	✓	–	–	–	–	–	–*	–*	–	✓*
Wisconsin Public Service	WEC	Elec.	✓*	–	–	–	–	–	–*	–*	–	✓*
Wisconsin Public Service	WEC	Gas	✓	–	–	–	–	–	–*	–*	–	✓*
WYOMING												
Cheyenne Light Fuel & Power	BKH	Elec.	✓	✓	–	✓*	✓*	–	–	–	–	✓*
Cheyenne Light Fuel & Power	BKH	Gas	✓	✓	–	✓*	–	–	–	–	–	–
MDU Resources	MDU	Elec.	✓	–	–	–	✓*	–	–	–	–	–
PacifiCorp	BRK.A	Elec.	✓	✓	–	–	✓*	✓*	–	–	–	–
SourceGas Distribution	–	Gas	✓	–	–	✓*	–	–	–	–	–	–

* See text for further information.

FOOTNOTES

Alabama

Electric Fuel/Gas Commodity/Purchased Power--The Certificated New Plant adjustment clause for Alabama Power provides for recovery of the costs (excluding fuel) associated with certified purchased power agreements. Adjustments under the clause are subject to a Staff and Alabama PSC review process that includes public hearings. Alabama Gas and Mobile Gas utilize a Competitive Fuel Clause that allows the companies to immediately adjust prices in order to compete with any alternate fuel or gas supply source, with no loss of earnings margin for the companies.

Decoupling--Alabama Gas and Mobile Gas use weather normalization clauses.

Environmental Compliance/Generation Capacity--The Certificated New Plant (Rate CNP) adjustment clause used by Alabama Power provides for recovery of costs related to: the commercial operation of certified generating facilities; certified purchased power agreements; and, environmental mandates. Recoverable environmental costs include: (1) applicable operation and maintenance expenses; (2) depreciation and a return on capital beginning with 2005 investments; and, (3) a true-up of prior period over/under-recovered amounts. Such costs are generally subject to PSC review, but not a full evidentiary hearing.

Other--The tariffs of the major energy utilities include adjustment provisions to reflect changes in income taxes, and certain general and local taxes.

Arizona

Decoupling--In 2011, the ACC adopted a full decoupling mechanism for Southwest Gas. In adopting the mechanism, the ACC authorized an ROE that was reduced by 25 basis points. Decoupling surcharges are capped at 5% of annual revenue, with amounts above the threshold deferred for future recovery. Recovery of the deferrals is subject to an earnings test.

In 2012, Arizona Public Service (APS) was authorized to implement a Lost Fixed Cost Recovery (LFCR) mechanism designed to make the company whole for contributions to fixed-cost-recovery that are lost due to customer participation in energy efficiency and distributed energy (roof-top solar) programs. Residential customers are permitted to opt out of the LFCR provisions if they agree to a rate structure that incorporates a higher basic service (fixed monthly) charge. The LFCR is capped at 1% of annual revenues, with any excess being deferred with interest to be recovered through a future annual adjustment.

In 2012, UNS Gas was authorized an incentive-based LFCR plan that allows the company to attain greater amounts of fixed-cost recovery as it meets its Commission-defined energy efficiency goals. Residential customers are permitted to opt out of the LFCR provisions if they agree to a rate structure that incorporates a higher basic service (fixed monthly) charge. The LFCR is capped at 1% of annual revenues, with any excess being deferred with interest to be recovered through a future annual adjustment.

In 2013, Tucson Electric Power was authorized to implement an LFCR mechanism to mitigate the revenue impact of lost sales associated with the ACC's energy efficiency standards and the distributed generation requirements under the Commission's renewable energy standards. The annual adjustments are to be capped at 1%, with any amount in excess of 1% to be deferred for future recovery. Residential customers have the option of paying a fixed monthly service charge in lieu of being subject to an LFCR mechanism.

In 2013, the ACC authorized UNS Electric to establish an LFCR mechanism, under which the company is permitted to implement annual rate adjustments related to any shortfall in recovery of fixed costs due to energy efficiency and distributed generation. The LFCR is not intended to recover fixed costs due to other factors, such as weather or general economic conditions, and, as such, is not considered a full decoupling mechanism. The annual adjustments are to be capped at 1%, with any amount in excess of 1% to be deferred for future recovery. The LFCR tariff is to reflect lost fixed costs beginning July 1, 2014. Residential customers have the option of paying a fixed monthly service charge in lieu of being subject to an LFCR mechanism.

Generation Capacity--In December 2014, the ACC authorized APS to implement a rider to reflect in rates the costs associated with the company's acquisition of a 48% share (739 MW) of the coal-fired Four Corners Units 4 and 5 (along with certain related facilities), and the retirement of Four Corners Units 1, 2, and 3 (100% owned by APS; 560 MW).

Other--All of the utilities recover franchise fees on a current basis through an adjustable line item on the monthly bill.

Arkansas

Decoupling--In 2010, the Arkansas PSC approved a framework (effectively a partial decoupling mechanism) that provides for the electric and gas utilities to recover the lost contribution to fixed costs associated with energy efficiency (EE)-related usage reductions and to retain a portion of the net benefits related to EE programs. (The gas utilities have been using full decoupling mechanisms for several years.)

Generation Capacity--Entergy Arkansas (EA) utilizes a capacity acquisition rider to recover costs associated with its investment in the Hot Spring generation plant.

Generic Infrastructure--EA uses a rider to recover costs associated with certain government-mandated investments.

Other--EA uses a storm recovery charges rider to collect from ratepayers the amounts required to service its related securitization bonds. Oklahoma Gas & Electric (OG&E) uses a "Smart Grid" rider. Arkansas Oklahoma Gas, CenterPoint Energy Resources, EA, OG&E, SourceGas Arkansas, and Southwestern Electric Power have a mechanism in place to recover variations in certain taxes and franchise fees.

Colorado

Decoupling--An adjustment clause is in place for Public Service Company of Colorado's (PSCO's) gas operations that includes a provision that provides recovery of lost revenues associated with customer participation in demand side management programs.

Environmental Compliance--Legislation enacted in 2010 allows an electric utility that is earning below its authorized equity return and operating under an emissions reduction plan approved by the Colorado Air Quality Control Commission designed to achieve a conversion or closure of coal-based generating capacity by Jan. 1, 2015, to, under certain circumstances, be accorded a special ratemaking mechanism designed to recover the costs of the approved plan.

Generation Capacity--In December 2014, the Colorado PUC authorized Black Hills Colorado Electric Utility (BHCE) to implement a rider that provides for the company to earn a cash return on construction work in progress related to a 40-MW gas-fired generating unit at the Pueblo Airport Generating Station that is expected to achieve commercial operation in early-2017.

Generic Infrastructure--PSCO and BHCE are permitted to recover, through a transmission cost adjustment (TCA) clause, prudent costs incurred in planning, developing, and completing construction or expansion of transmission facilities for which the PUC has granted a certificate of public convenience and necessity or has otherwise determined to be necessary. Through the TCA, the utilities may earn a cash return on construction work in progress for investments in grid reliability or new or upgraded transmission facilities. The TCAs are updated annually.

PSCO operates under a pipeline system integrity adjustment mechanism for its gas operations, through which the company recovers the costs associated with reliability improvements and compliance with certain federal safety regulations. The mechanism is to expire on Dec. 31, 2015.

Other--PSCO utilizes an adjustment clause for steam service under which it recovers the difference between its actual cost of fuel and the costs recovered in base rates.

PSCO shares with customers margins from generation-based short-term energy trading and proprietary trading through its fuel and purchased power adjustment mechanism. Any margins associated with the sale of proprietary-based renewable energy credits are to be reflected in the calculation of proprietary trading margins. BHCE uses an off-system sales margin-sharing mechanism as a component of its fuel cost/purchased power expense cost adjustment mechanism.

Connecticut

Electric Fuel/Gas Commodity/Purchased Power--United Illuminating (UI) and Connecticut Light & Power (CL&P) no longer own generation, and both are permitted to recover, on a current basis, their full costs of providing generation service to those customers who do not choose an alternative supplier. These costs are flowed through to ratepayers outside of a rate case.

Decoupling--Legislation enacted in 2013 mandates the adoption of decoupling mechanisms for the electric and gas utilities. UI, CL&P, and Connecticut Natural Gas (CNG) currently have decoupling mechanisms in place.

Generic Infrastructure--A 2013 Connecticut PURA order established a system expansion reconciliation mechanism that permits the gas utilities to reconcile gas-expansion-related revenue annually, between rate cases. CNG also utilizes a Distribution Integrity Management Program (DIMP) mechanism that allows for recovery, between rate cases, of the costs associated with main replacement activity. Ratepayers do not see a separate charge on their bills. Instead, the DIMP charge is included in base distribution rates.

Delaware

Electric Fuel/Gas Commodity/Purchased Power--In conjunction with the implementation of retail competition, Delmarva Power & Light's electric fuel adjustment was largely eliminated. Power to meet standard-offer-service needs is now procured competitively and reflected in rates on a current basis.

Other--Chesapeake Utilities has a mechanism in place to recover variations in certain taxes and fees.

District of Columbia

Electric Fuel/Purchased Power--Fuel and purchased power adjustment clauses are permitted by law. However, with the onset of electric retail competition, Potomac Electric Power (Pepco) divested most of its generation assets; the assets that were not divested have since been retired. Pepco purchases the power to meet its standard-offer-service (SOS) requirements via a competitive bidding process, and prices paid by SOS customers reflect the weighted average of the winning bids; SOS prices are adjusted on a current basis.

Decoupling--A Bill Stabilization Adjustment mechanism, applied monthly, is in place for Pepco that is designed to mitigate the volatility of revenues and customer bills caused by abnormal weather and customer participation in energy efficiency programs.

Renewables Expense--Pepco's rates include a surcharge to fund the Sustainable Energy Trust Fund; amounts collected are remitted to the third-party Sustainable Energy Utility.

Generic Infrastructure--In May 2014, legislation was enacted that provides for the District to issue revenue (securitization) bonds, to finance a portion of the costs associated with a plan under which Pepco is to relocate certain above-ground distribution facilities below ground. In addition, the bill authorizes the District of Columbia PSC to approve a surcharge mechanism to achieve rate recognition of the unsecuritized portion of the project. In November 2014, the PSC approved the undergrounding program, known as the DC PLUG initiative, and established a rider for rate recognition of the investment.

For Washington Gas (WG), costs associated with PSC-mandated replacement and encapsulation of certain couplings may be recovered through a surcharge on distribution rates. In January 2015, the PSC approved a $1 billion, 40-year accelerated pipeline replacement program for WG, and approved a surcharge mechanism for recovery of the first five years of the program.

Other--A gas administrative charge is part of WG's purchased gas charge and provides for recovery of uncollectible expenses related to gas commodity charges, rather than recovering those expenses in base rates. WG is also permitted to recover carrying costs on storage balances and over/undercollected gas costs through separate surcharges. Pepco and WG have a mechanism in place to recover variations in certain taxes and fees.

Florida

Generation Capacity--Electric utilities are permitted to recover all prudently incurred site selection and preconstruction costs, including carrying charges, for nuclear and integrated gasification combined-cycle (IGCC) power plants through the capacity cost recovery clause (CCRC). A cash return on construction work in progress for nuclear plant construction and uprates and IGCC construction is also reflected in the CCRC.

Florida Power & Light uses a "generation base rate adjustment" (GBRA) to recover the base revenue requirement associated with each of three approved power plant modernization projects upon their commercial operation. One project achieved commercial operation in 2013, one in 2014, and the third is expected to do so in June 2016. Each generation-related base rate increase will be calculated using a 10.5% ROE and be effectuated through the company's capacity clause.

As specified in a settlement adopted in 2013, Duke Energy Florida is authorized to increase base rates without a general rate case through a GBRA to recover the costs of up to 1,800 MW of additional new generation in 2018. Adjustments under the GBRA are to reflect a 10.5% ROE and the most recent capital structure from the company's periodic surveillance reports that are filed with the Florida PSC.

As part of a 2013 PSC rate case decision, Tampa Electric is to implement a $110 million rate increase through a GBRA on the later of Jan. 1, 2017, or the date the conversion of Units 2 to 5 of the Polk Power Station are completed.

Generic Infrastructure--Peoples Gas System utilizes a rider to recover, through an annual surcharge, the costs associated with accelerating the replacement of cast iron and bare steel distribution pipes on its system over a 10-year period that began in 2013. The smaller gas utilities, Florida Public Utilities, the Florida division of Chesapeake Utilities, and Pivotal Utility Holdings, use similar riders.

Other--Certain fees and taxes, such as franchise fees and gross receipts taxes, are recovered through a line item on customer bills, with the charge adjusted based on customer usage. The fuel and purchased power cost recovery clause reflects gains from economy energy sales.

Georgia

Fuel Costs--As a result of the restructuring of the natural gas industry in Georgia, Atlanta Gas Light (ATGL) no longer procures gas for its customers and, thus, is no longer subject to the purchased gas adjustment mechanism (PGAM). The much smaller Liberty Utilities (Peach State Natural Gas), which is still regulated under a non-restructured framework, utilizes a non-automatic PGAM.

Decoupling--Liberty Utilities (Peach State Natural Gas) is subject to the Georgia Rate Adjustment Mechanism (GRAM), an alternative regulatory framework. The GRAM provides for a "revenue true-up," under which the company is to compare actual revenues to the previous revenue projection. ATGL operates under straight fixed-variable rates.

Environmental Compliance--ATGL is authorized to recover clean-up costs related to former manufactured gas plant sites through an environmental response cost recovery rider (ERCRR). Costs that are recoverable under the ERCRR include investigation, testing, remediation, and/or litigation costs or other liabilities.

Generation Capacity--A nuclear construction cost recovery (NCCR) tariff is in place for Georgia Power (GP). The NCCR tariff enables GP to earn a cash return on construction work in progress related to Plant Vogtle Units 3 and 4, two 1,100-MW nuclear units. The NCCR tariff is to be revised annually.

Generic Infrastructure--The Georgia PSC approved a Strategic Infrastructure Development and Enhancement (STRIDE) program for ATGL in 2009, specifying infrastructure investments for the next ten years. Every three years, ATGL is required to file its proposed program for the next three years for PSC review and approval. The incremental costs associated with the program's investment are to be included in base rates each Oct. 1. The STRIDE program was expanded in August 2013 and December 2013.

Hawaii

Generation Capacity/Generic Infrastructure--As part of their alternative regulation frameworks, Hawaiian Electric Company, Hawaii Electric Light Company, and Maui Electric Company are permitted to recognize rate base additions and increases in operation and maintenance expenses, and certain depreciation and amortization expenses between rate cases.

Idaho

Electric Fuel/Gas Commodity/Purchased Power--Avista Corporation's power cost adjustment enables the company to defer, in a balancing account, for subsequent recovery/refund to customers, 90% of the difference between actual net power costs and the amount included in retail rates. Idaho Power (IP) has a similar mechanism in place with a sharing provision under which annual rate adjustments reflect 95% of the cost variations associated with water supply for hydro-electric production, wholesale energy prices, and retail load changes. An energy cost adjustment mechanism is in place for PacifiCorp that allows for the recovery of 90% of the difference between actual power costs and those included in rates.

Decoupling--IP operates under a revenue decoupling mechanism, referred to as a Fixed Cost Adjustment (FCA), which is designed to adjust the company's electric rates to recover fixed costs independent of the volume of energy sales. On May 6, 2015, the Idaho PUC approved a settlement that modified the FCA by replacing weather-normalized sales with actual sales in the calculation of the FCA. The modifications take effect beginning in calendar-year 2015, and thereafter and is to be reflected in rates effective June 1, 2016. There is a 3% cap on annual rate increases that may be implemented under the mechanism.

Illinois

Electric Fuel/Gas Commodity/Purchased Power--Historically, the large electric utilities were permitted to recover fuel costs and the energy component of purchased power costs through a monthly automatic fuel adjustment clause (FAC). Their FACs were discontinued in conjunction with the implementation of electric industry restructuring. The power to meet the utilities' standard-offer-service (SOS) obligations is now procured competitively; SOS costs and revenues are subject to an annual true-up mechanism.

Environmental Compliance--Ameren Illinois (AI) uses a hazardous materials adjustment clause rider, largely to address asbestos-related litigation and remediation costs. AI, Commonwealth Edison (ComEd), Peoples Gas Light & Coke (Peoples), North Shore Gas (North Shore), and Northern Illinois Gas (NI-Gas) use riders to recover costs related to the investigation and cleanup of manufactured gas plants.

Generic Infrastructure--In accordance with legislation enacted in 2013, the ICC is permitted to approve adjustment clauses for the local gas distribution companies to recover the costs associated with their infrastructure replacement programs, and the ICC has done so for Peoples Gas Light & Coke (Peoples), NI-Gas, and AI.

Other--As permitted by state statutes, AI, ComEd, NI-Gas, Peoples, North Shore, and MidAmerican Energy utilize riders to facilitate recovery of variations in bad-debt costs. AI, ComEd, MidAmerican Energy, Peoples, North Shore, and NI-Gas have a mechanism in place to recover variations in certain taxes and franchise fees.

Indiana

Decoupling--Indianapolis Power & Light's (IP&L's), Indiana Michigan Power's (IMP's), Duke Energy Indiana's (DEI's), and Northern Indiana Public Service Company's (NIPSCO's) energy efficiency riders provide for recovery of net lost revenues (deferral of lost revenues is currently authorized for IP&L) and shared savings (except for NIPSCO), subject to Commission approval.

Indiana Gas (IG) and Southern Indiana Gas & Electric Company (SIGECO) utilize energy efficiency riders to recover the costs associated with their natural gas energy efficiency programs. The riders include a Sales Reconciliation Component, to provide the companies an opportunity to recoup revenues lost as a result of the conservation programs. SIGECO and IG also utilize a normal temperature adjustment mechanism to eliminate the impact of weather deviations on gas distribution revenues.

Environmental Compliance--State law allows the URC to authorize the electric utilities to recover, through a rate adjustment mechanism, 80% of the costs associated with certain federally-mandated emissions-control and transmission/distribution reliability projects. The remaining 20% of such costs are to be deferred for future recovery. Environmental cost recovery riders are in place for DEI, NIPSCO, IP&L, and IMP. Through these riders, the utilities are permitted to recover related operation and maintenance costs and depreciation expense after the environmental facilities become operational, as well as a return on the related investment. These riders also provide for recovery of the net costs associated with the purchase of emission allowance credits.

Generation Capacity--With respect to DEI's Edwardsport integrated gasification combined-cycle plant, the company was authorized to earn a cash return on construction work in progress associated with the plant, which commenced commercial operation in 2013, through a rider; the company now recovers the plant's operating costs through the rider.

Generic Infrastructure--In 2013, legislation was enacted that provides for the URC to authorize the utilities to implement a transmission, distribution, and storage system improvement charge rider to facilitate recovery of the costs associated with certain electric and gas infrastructure expansion projects, including those intended to improve safety or reliability, modernize the utility's system, or improve an area's economic development prospects. The URC has approved such a rider for NIPSCO's electric and gas operations, and for IG's and SIGECO's gas businesses. However, the Commission is addressing certain aspects of an April 2015 Indiana Court of Appeals remand that requires additional specificity with respect to the latter years of the companies' infrastructure investment programs.

SIGECO and IG utilize a pipeline safety adjustment (PSA) mechanism that allows the companies to recover incremental non-capital expenses incurred due to requirements of the Federal Pipeline Safety Improvement Act of 2002. All incremental operation and maintenance costs incurred after Jan. 1, 2014 are to be included in the companies' "compliance and system improvement adjustment" mechanism.

Other--DEI, IMP, SIGECO, and NIPSCO are permitted to equally share with ratepayers, through a rider, off-system sales (OSS) margins that vary from the amount reflected in the companies' base rates. IMP uses a rider for recovery of costs associated with the AEP Power Pool capacity cost-sharing arrangement.

SIGECO utilizes a semi-annual Reliability Cost and Revenue Adjustment that reflects: municipal wholesale margins; net emission allowance costs; interruptible sales billing credits; non-fuel purchased power costs; and, ratepayers' share of the difference between actual wholesale power margins and the level of such margins included in base rates. SIGECO and IG have riders in place for a portion of the incremental changes in unaccounted-for gas costs and the gas-cost component of bad debts. (NIPSCO includes these costs in its gas cost adjustment filings.)

Iowa

Environmental Compliance--Incremental revenues and costs associated with sales or purchases of emission allowances may be reflected in Interstate Power & Light's (IP&L's) and MidAmerican Energy's energy adjustment clauses.

Other--MidAmerican uses a rider to recover certain feasibility study costs related to its analysis of the merits of building a new nuclear plant. Black Hills/Iowa Gas Utility, IP&L, and MidAmerican Energy have a mechanism in place to recover variations in certain taxes and franchise fees.

Kansas

Conservation Program Expense/Decoupling--Legislation enacted in 2014 allows the electric and gas utilities to request KCC approval to implement energy efficiency (EE)-related cost recovery mechanisms. Westar Energy and KG&E participate in certain EE programs and recover program-related costs and the related lost revenues through the companies' EE cost recovery riders. These mechanisms were in place prior to the legislation. Weather normalization adjustment clauses are in place for Atmos Energy, Black Hills/Kansas Gas Utility (KGU), and Kansas Gas Service (KGS).

Generic Infrastructure--State law permits the local gas distribution companies to utilize a gas system reliability surcharge (GSRS) mechanism to recover the costs associated with gas distribution system replacement projects between base rate proceedings, subject to annual true-up. The utilities are prohibited from utilizing GSRS mechanisms for periods exceeding five years; GSRS balances are to be reset to zero, with amounts recovered through the surcharge to be rolled into base rates in the utility's next rate proceeding. In addition, a utility may not request changes in the GSRS rate more often than every 12 months. Atmos, KGS, and KGU have a GSRS in place.

Other--Although not an adjustment clause per se, the KCC is statutorily authorized to permit the utilities to file "abbreviated" rate cases, within 12 months of a Commission rate order in the utility's most recent base rate proceeding. Such filings must incorporate all of the regulatory procedures, principles, and rate-of-return parameters established by the KCC in that order.

KGU recovers 100% of the gas cost component of bad debt expense through the company's purchased gas adjustment clause filings. Kansas City Power & Light (KCP&L), Westar, KG&E, and Empire District Electric (Empire) flow to ratepayers, through their energy cost adjustment mechanisms, off-system sales margins that vary from a base level and the net cost of emissions allowances. KCP&L, Westar/KG&E, Empire, Atmos, KGU, KGS have a mechanism in place to recover variations in certain taxes and franchise fees.

Kentucky

Decoupling--Weather normalization adjustment mechanisms are in place for Atmos Energy (Atmos), Columbia Gas of Kentucky (CGK), Delta Natural Gas (Delta), and Louisville Gas & Electric's (LG&E's) gas operations. Duke Energy Kentucky (DEK), LG&E, Atmos, CGK, and Delta utilize energy efficiency riders to facilitate recovery of costs associated with gas energy efficiency programs; these riders include certain incentive provisions and permit recovery of lost revenues related to these programs. LG&E, DEK, Kentucky Utilities (KU), and Kentucky Power (KP) also utilize a similar mechanism for their electric businesses.

Environmental Compliance--LG&E, KU, and KP are permitted to recover the costs associated with environmental-related investments (including the cost of emissions allowances), and earn a cash return on the related construction work in progress, through a cost recovery mechanism. Proceedings are conducted every two years to evaluate the operation of the mechanism and to set the level of such charges to be included in base rates.

Generation Capacity--KP utilizes a rider to recover the costs related to the retirement of the coal-fired Big Sandy Unit 1 and 2 plants, and a separate rider for certain non-fuel-related costs associated with operating the Big Sandy Unit 1 plant both as a coal-fired unit (through June 30, 2016) and as a gas-fired unit (beginning July 1, 2016).

Generic Infrastructure--Atmos, CGK, LG&E, and Delta utilize riders to facilitate recovery of costs associated with their infrastructure replacement programs.

Other--KP has a rider in place to recover certain costs related to compliance and cyber-security requirements imposed by the North American Electric Reliability Corporation. Off-system sales (OSS) sharing mechanisms are in place for DEK's electric operations and for KP. 100% of DEK's prospective emission allowance sales margins flow to ratepayers through the OSS mechanism. Atmos, CGK, Delta, DEK, KP, LG&E, and KU have a mechanism in place to recover variations in certain taxes and franchise fees.

Louisiana - NOCC

Decoupling--Entergy New Orleans (ENO) had been recovering lost revenues (excluding the effects of weather) associated with conservation/efficiency programs through its now-expired electric formula rate plan (FRP). ENO's fuel clause includes (for legacy Entergy Louisiana [EL] Algiers service territory customer only) a provision that provides for the recovery of the "Lost Contribution to Fixed Costs" associated with customer participation in energy efficiency programs.

Environmental Compliance--An environmental adjustment clause rider is in place for ENO, through which the company recovers costs associated with the purchase and use of emission allowances.

Generation Capacity--In July 2014, the NOCC authorized EL to implement, as a provision of its FRP, an interim rider to recover certain costs associated with its investment in the Ninemile unit 6 facility, which began operating in late-2014. The rider was implemented in February 2015. Following the NOCC's approval of the transfer of EL's Algiers service territory to ENO, recovery of the interim Ninemile 6 costs was transferred to a separate mechanism.

Other--ENO uses a storm-reserve rider for both its electric and gas operations.

Louisiana PSC

Decoupling--Energy efficiency (EE) riders are in place for the state's electric utilities through which the companies recover costs associated with administering their EE programs and the "Lost Contribution to Fixed Costs" associated with customer participation in the programs. CenterPoint Energy Resources, Atmos Energy divisions Louisiana Gas Service (LGS) and TransLouisiana Gas (TLG), and the gas operations of Entergy Louisiana utilize weather normalization adjustment mechanisms.

Environmental Compliance--The state's electric utilities may use an environmental adjustment clause (EAC) to recover from ratepayers the costs associated with the acquisition of emissions credits to comply with federal, state, and local environmental standards. In addition, the utilities credit ratepayers through the EAC any revenues associated with the sale or transfer of emission allowances.

Generation Capacity--A component of Entergy Louisiana's (EL's) formula rate plan (FRP) provides for the recovery of costs associated with new generation and capacity additions, including the Ninemile 6 facility.

Generic Infrastructure--As part of their rate stabilization clauses, LGS and TLG have a mechanism in place that provides for the deferred recovery of costs associated with system integrity management programs. An infrastructure investment recovery rider is in place for EL's gas operations.

RTO-Related Transmission Expense--EL recovers certain transmission-related costs through its FRP.

Other--Customers' share of Southwestern Electric Power's off-system sales margins flow through the company's fuel adjustment clause. Cleco Power and EL have securitization-related riders in place.

Maine

Fuel Costs/Purchased Power Costs--Electric fuel adjustment clauses are no longer utilized due to the implementation of retail choice. For the most part, the state's electric utilities no longer own generation, and by law are not allowed to provide standard offer service (SOS). SOS providers are selected through a bidding process conducted by the Maine PUC. The full cost of SOS is recovered from ratepayers.

Decoupling--In September 2014, Central Maine Power (CMP) began operating under a full revenue decoupling mechanism. Any related annual adjustments are to be capped at 2% of distribution revenues, with any undercollection amount in excess of 2% to be deferred for future recovery. No cap would apply to the amount of over-collection to be returned to ratepayers.

Environmental Compliance--Northern Utilities (NU) recovers manufactured gas site remediation expenses through an environmental remediation charge that is adjusted on a semi-annual basis.

Generic Infrastructure--NU utilizes a targeted infrastructure replacement adjustment (TIRA), which is to be in place for a four-year period beginning in 2013. The TIRA provides for recovery of the company's investments in targeted operational and safety-related infrastructure replacement and upgrade projects.

Other--In August 2014, the PUC authorized CMP to implement a storm cost recovery mechanism that allows the company to recover variations in storm costs versus the levels included in base rates.

Maryland

Electric Fuel/Purchased Power--Historically, electric utilities were permitted to recover the fuel and energy portion of purchased power costs through the electric fuel rate (EFR). The EFR was eliminated, coincident with the implementation of competition in the provision of electric supply. The utilities continue to provide electric supply service to customers who do not select an alternative generation supplier; the power to meet these requirements is obtained via competitive bids and the costs are recovered from ratepayers on a current basis.

Conservation Program Expense--Maryland's electric and gas utilities have riders in place, which are adjusted annually, to reflect recovery of electric and gas energy efficiency and demand-side program costs that are not included in base rates.

Decoupling--Columbia Gas of Maryland (CGM) and Washington Gas (WG) have revenue normalization adjustment mechanisms in place for residential customers only.

Generic Infrastructure--Potomac Electric Power (Pepco) uses a grid resiliency charge to recover the costs associated with its accelerated-feeder-replacement program. A similar program and rider are in place for Delmarva Power & Light.

State law permits the Maryland PSC to authorize the gas utilities to implement surcharges to recover costs associated with approved accelerated infrastructure replacement programs, establishing the Strategic Infrastructure Development and Enhancement (STRIDE) Program. The PSC has approved a gas STRIDE program and an associated rider for Baltimore Gas & Electric (BG&E), WG, and CGM.

Other--BG&E, CGM, Potomac Edison, Pepco, and WG have a mechanism in place to recover variations in certain taxes and fees.

Massachusetts

Electric Fuel/Gas Commodity/Purchased Power--Quarterly electric fuel and purchased power adjustments were eliminated coincident with the start of retail competition. Rates for basic service (a.k.a. default service) are market-based; such rates reflect the competitive contracts for basic service supply entered into by the distribution utility. The utilities are not at risk for fluctuations in market prices.

Conservation Program Expense/Environmental Compliance/Other--The DPU has adopted energy efficiency reconciliation factors (EERF) for the state's electric utilities. The EERF is a fully-reconciling funding mechanism designed to recover the costs associated with the state's electric energy efficiency investments that are in excess of the level collected from other funding sources, including the systems benefits charge, proceeds from the forward capacity market, and proceeds from the Regional Greenhouse Gas Initiative.

Local gas distribution adjustment clauses (LDACs) are in place, with rate changes implemented on a semi-annual basis to reflect recovery of reconcilable gas-distribution-related costs that are not included in base rates. Such expenses include demand-side management costs, environmental response costs associated with manufactured gas plants, residential arrearage management programs, low income discounts, pension and related costs, the revenue requirement on targeted infrastructure recovery factors (TIRF) and gas system enhancement programs (GSEP) investment, and attorney general expenses. LDACs are applicable to all firm customers.

Renewables Expense/Generation Capacity--A cost adjustment tariff is in place for Western Massachusetts Electric Company's (WMECO's) and Massachusetts Electric's (ME's) investments in certain solar generation facilities.

Generic Infrastructure--In accordance with 2014 legislation, each of the state's LDCs files with the DPU a plan, called a "Gas System Safety Enhancement Program," (GSEP) to address aging or leaking natural gas infrastructure. Initially, LDCs that seek to participate in the program must file a plan that is designed to remove leak-prone cast iron and unprotected steel piping from the LDC's system over a 20-year period. Participating LDCs must file by each Oct. 1 a list of projects the utility plans to complete during the upcoming construction season, as well as proposed adjustments to distribution rates effective May 1 of the following year that will allow for recovery of program-related costs. The law specifies the criteria that the DPU must apply during its evaluation of the LDC's plan and, if the plan meets those criteria, the Department must approve the plan and the adjusted distribution rates. On or before May 1 of each year during an LDC's program, the LDC must file final documentation for projects completed during the prior year to demonstrate substantial compliance with its plan in effect for that year and that project costs were reasonably and prudently incurred. The LDC's May 1 filing reconciles the estimated costs that were approved for recovery to the actual costs incurred during the year, and adjustments to distribution rates (for recovery or refund) are made accordingly. The ROE authorized in the company's most recent rate case is to be utilized in its GSEP rider. Annual changes in the revenue requirement eligible for recovery may not exceed 1.5% of the company's most recent calendar year total firm revenues, including gas revenues attributable to sales and transportation customers. Any revenue requirement approved by the DPU in excess of the cap may be deferred for recovery in the following year. Previously, some of the state's gas utilities used targeted infrastructure replacement mechanisms.

ME's decoupling mechanism includes a tracking mechanism to reflect capital investment of up to $170 million. Amounts over the cap are to be addressed in the company's next general rate proceeding.

Other--Recovery mechanisms for pension and post-employment-benefits-other-than-pensions are in place for ME, WMECO, NSTAR Electric, NSTAR Gas, Fitchburg Gas and Electric, Liberty Utilities (New England Gas), Boston Gas/Essex Gas, Colonial Gas, and Bay State Gas. The utilities file annually for recovery of pension and post-employment-benefits-other-than-pensions not currently reflected in rates. Such costs are to be recovered through the LDAC reconciliation mechanism for gas utilities and a separate rate component for electric utilities.

Michigan

Decoupling--The Michigan PSC had approved the implementation of electric RDMs for Consumers Energy (CE), Upper Peninsula Power (UPP), and DTE Electric (DTE-E); however, in 2012, the Michigan Court of Appeals ruled that the PSC does not have statutory authority to approve RDMs for electric utilities.

State law permits a gas utility that spends at least 0.5% of its revenue on energy efficiency programs to institute a revenue decoupling mechanism (RDM). In 2010, the PSC adopted energy-efficiency-related pilot RDMs for the gas operations of CE, Michigan Gas Utilities (MGU), and DTE Gas (DTE-G); however, in 2012, CE's gas RDM was terminated. In January 2015, the PSC adopted a settlement authorizing CE to implement a gas RDM, effective January 2016. In 2012, the PSC adopted a settlement in a DTE-G rate case that terminated the company's RDM; however, a modified RDM was instituted for DTE-G in 2013. Effective Jan. 1, 2014, MGU's RDM was terminated; however, a new RDM became effective Jan. 1, 2015.

Generic Infrastructure--DTE-G utilizes an Infrastructure Recovery Mechanism that enables it to earn a return of, and on, the costs associated with capital investment in the company's meter move-out, accelerated main replacement, and pipeline integrity programs.

RTO-Related Transmission Expense--CE, DTE-E, and UPP recover transmission costs through the power supply cost-recovery mechanism.

Minnesota

Decoupling--In 2012, the Minnesota PUC authorized Minnesota Energy Resources to implement, effective Jan. 1, 2013, a pilot, three-year revenue decoupling mechanism (RDM) that applies to the company's residential and small commercial/industrial rate classes and is to adjust revenues for variations from any cause, including weather. There is a 10% symmetrical cap on revenue changes generated through the application of the RDM, and the mechanism utilizes per-customer distribution revenues for each rate group. Rate changes required by the operation of the RDM are implemented annually.

In a May 2014 decision in a general rate case, the PUC authorized CenterPoint Energy Resources (CER) to implement a pilot, three-year, full RDM effective July 1, 2015. The RDM is to apply to all customer classes except market-rate customers, subject to a cap on annual adjustments under the mechanism that is equal to 10% of non-gas margin revenue, after removing conservation costs, for decoupling adjustments due to revenue under-recovery by CER.

On March 26, 2015, the PUC authorized Northern States Power-Minnesota (NSP-M) to implement a pilot, three-year full RDM with a 3% cap on base revenues for the residential, small commercial, and small industrial classes, to be effective Jan. 1, 2016. NSP-M can seek to recover amounts over the cap provided it can show that its demand-side management and/or other initiatives were a substantial contributing factor to the declining energy consumption and that other non-conservation factors were not the primary factors for the under-recovery.

Generic Infrastructure--NSP-M uses a Gas Utility Infrastructure Cost Rider to recover the costs associated with certain gas infrastructure upgrades, especially those that are safety-related, outside of a general rate case.

Mississippi

Decoupling--Atmos Energy utilizes a weather normalization adjustment rider that is in place during the months of November through April and is adjusted monthly during that time. Entergy Mississippi (EM) and Mississippi Power (MP) have energy efficiency (EE) riders in place that provide for recovery of EE program costs and the lost contributions to fixed costs associated with such programs.

Environmental Compliance--EM and MP are permitted to recover emissions allowance expenses through their fuel adjustment clauses. MP utilizes an Environmental Compliance Overview (ECO) plan. The ECO plan establishes procedures to facilitate the Mississippi Public Service Commission's (PSC's) review of the company's environmental compliance strategy and provides for rate recovery of costs (including the cost of capital) associated with PSC-approved environmental projects, on an annual basis, outside of a base rate case.

New Capital Investment--Until late-2014, the company had been recovering the costs associated with the gas-fired Attala power plant and the Hinds Energy Center through a temporary power management rider. However, as part of a rate case decision issued in December 2014, these amounts were rolled into base rates, and removed from the rider.

Other--EM and MP have riders in place related to the securitization of storm costs.

Missouri

Conservation Program Expense/Decoupling--The local gas distribution companies may request Missouri PSC approval of a mechanism to reflect the impact of changes in customer usage due to variations in weather and/or conservation. KCP&L has in place a demand-side programs investment mechanism that provides for recovery of program-related costs and the related lost revenues. KCP&L-Greater Missouri Operations (GMO) and UE have similar mechanisms in place for their electric operations.

Renewable Energy--The PSC's rules specify that the electric utilities may file for a Renewable Energy Standards rate adjustment mechanism (RESRAM) to reflect prudently incurred costs or a pass-through of benefits received, as a result of compliance with the state's renewable energy standards. The RESRAM is to be capped at a 1% annual rate impact. GMO has a RESRAM in place.

Environmental Compliance--The PSC's rules pertaining to Environmental Cost Recovery Mechanisms (ECRMs) specify that a portion of the utility's environmental costs may be recovered through an ECRM and a portion may be recovered through base rates; the annual recovery of these costs is to be capped at 2.5% of the utility's Missouri gross jurisdictional revenues, less certain taxes. None of the utilities currently have an ECRM in place; however, Empire District Electric (Empire), GMO, and Union Electric (UE) recover emissions allowance costs through their FACs.

Generic Infrastructure--Liberty Utilities (Midstates Natural Gas), Laclede Gas, Missouri Gas Energy (MGE), and UE utilize an infrastructure system replacement surcharge to recover costs associated with certain gas distribution system replacement projects.

Other--Off-system sales margins that vary from the levels included in base rates flow through the FACs of Empire, GMO, and UE. Liberty Utilities (Midstates Natural Gas), Empire, KCP&L, GMO, Laclede, MGE, and UE have a mechanism in place to recover variations in certain taxes and franchise fees.

Montana

Electric Fuel/Gas Commodity/Purchased Power--In accordance with the state's restructuring statutes, NorthWestern Corp. sold its generation assets and entered into purchased power contracts with competitive suppliers to serve provider-of-last-resort customers. NorthWestern recovers supply costs through a cost recovery mechanism, adjusted monthly, under which rates are based on estimated loads and electricity costs for the upcoming tracking period. The Montana PSC reviews and adjusts rates for differences between estimates and actual results. MDU Resources Group (MDU) utilizes a monthly-adjusted fuel and purchased power cost recovery mechanism.

Decoupling--NorthWestern is permitted to recoup revenues lost as a result of electric demand-side management programs in the context of its annual default supply cost recovery filings. The Montana PSC has indicated that it will issue an order in the near future discontinuing the company's lost revenue adjustment mechanism. MDU utilizes a mechanism to recover the costs associated with gas conservation programs, as well as to recoup revenues lost as a result of the programs.

Other--A competitive transition charge mechanism is in place for NorthWestern through which the company recovers electric-restructuring-related out-of-market costs associated with certain purchased power contracts. A similar transition charge is in place for the company's gas operations. NorthWestern is also currently reflecting, in its gas commodity mechanism on an interim basis, costs related to certain natural gas production assets it recently acquired, pending a review by the PSC. For MDU, off-system sales margins are shared by ratepayers and shareholders on a 90%/10% basis through the fuel clause.

Nebraska

Generic Infrastructure--The gas utilities are allowed to apply for approval to use an infrastructure system replacement cost recovery (ISRCR) rider. The ISRCR rider is to provide for timely recovery of certain capital investments outside of a general rate case and is to be capped at 10% of a utility's Nebraska-jurisdictional annual base revenue level. Following Nebraska PSC approval, an ISRCR rider is to expire upon the earlier of: the implementation of new rates stemming from the conclusion of a general rate case filed subsequent to the PSC's approval of the ISRCR rider; or, 60 months. Black Hills Nebraska Gas Utility utilizes an ISRCR rider. SourceGas Distribution (SG) has a forward-looking system safety and integrity rider tariff and system and integrity rider charge in place.

Other--SG uses a surcharge through which the company recovers external rate case expenses of the Office of the Public Advocate and the PSC that are assessed to the utility. All of the utilities have line items on their bills through which variations in franchise fees are recovered.

Nevada

Decoupling--The lost revenues associated with energy efficiency and conservation programs for Sierra Pacific Power (SPP) and Nevada Power (NP) are recovered using a periodically adjusted balancing account, referred to as the lost revenue adjustment mechanism.

State law and Nevada PUC rules include provisions, including revenue decoupling, to address disincentives to gas company participation in energy conservation programs. Southwest Gas has a decoupling mechanism in place.

Generic Infrastructure--PUC rules allow for the establishment of a gas infrastructure replacement mechanism that will permit the utilities to recover, between rate cases, the revenue requirement associated with their gas infrastructure replacement projects. Southwest Gas currently has such a rider in place.

Other--Southwest Gas utilizes a mechanism designed to allow the company to recover from, or refund to, ratepayers the difference between actual bad debt expenses and the level reflected in base rates.

New Hampshire

Electric Fuel/Gas Commodity/Purchased Power--Fuel and purchased power adjustment clauses had been utilized prior to the implementation of retail choice in the early 2000s. Public Service Company of New Hampshire (PSNH) now recovers its power costs through a periodically-adjusted default service rate, which reflects the revenue requirements of its generating assets and the cost of power purchases. It also includes a reconciliation of the difference between the company's costs and revenues for the previous period.

Liberty Utilities (Granite State Electric) and Unitil Energy Systems sold their generation as part of their restructuring agreements. These distribution-only companies supply default energy service through a request-for-proposals process supervised by the New Hampshire PUC.

Generic Infrastructure --A cast iron/bare steel rate adjustment mechanism is in effect for Liberty Utilities (EnergyNorth Natural Gas). Reliability enhancement and vegetation management programs and accompanying riders are in effect for Liberty Utilities (Granite State Electric), PSNH, and Unitil Energy Systems. The programs provide for recovery of both the capital investment and increases to operation and maintenance expense necessary for ongoing system reliability and vegetation management efforts.

New Jersey

Electric Fuel/Purchased Power/Gas Commodity--Historically, the utilities were permitted to reflect variations in fuel and purchased power costs through the Levelized Energy Adjustment Clause (LEAC); however, the LEAC was suspended with the onset of retail competition. The utilities now procure power to meet customer requirements in the wholesale market and are permitted to flow these costs to ratepayers on a current basis.

Decoupling--Weather normalization clauses are in place for Pivotal Utility Holdings (PUH) and the gas operations of Public Service Electric & Gas (PSEG). A version of a revenue decoupling mechanism is in place for New Jersey Natural Gas (NJNG) and South Jersey Gas (SJG). Operation of the mechanisms is contingent on the companies achieving certain capacity-reduction targets and earnings tests as specified in their BPU-approved conservation incentive programs.

Environmental Compliance--PUH, PSEG, NJNG, and SJG are permitted to recover costs associated with former manufactured gas plant site cleanup outside of base rates through an adjustment mechanism. Such expenses are deferred and recovered over rolling seven-year periods, including carrying costs on the unamortized balance.

Generic Infrastructure--During 2009 through 2011, the BPU approved economic stimulus programs proposed by the electric and gas utilities at the Board's request. The programs provided for the acceleration of various infrastructure development projects. The companies were permitted to recover the costs (including a return on investment) associated with these programs, on an expedited basis, outside of a base rate case. The rate recovery process for approved programs is largely complete. There were riders for some of the companies for one year and then all had to recover through base rates. In 2013, following Hurricane Sandy, the BPU directed the utilities to develop mitigation and hardening infrastructure modernization plans, and indicated that it would be open to innovative cost-recovery mechanisms for such plans.

In 2014, the BPU approved PSEG's "Energy Strong" infrastructure investment program (for electric and gas operations, NJNG's New Jersey Reinvestment in System Enhancement program, and SJG's accelerated resiliency improvement program. An accelerated infrastructure investment program was approved for PUH, but the related costs are to be deferred for recovery in base rates. In a rate case decided in March 2015, the BPU rejected a Jersey Central Power & Light's request for approval of an accelerated reliability enhancement program and a related recovery mechanism.

Other--All of the utilities have a mechanism in place to recover variations in certain taxes and fees. In addition, the electric utilities recover certain costs associated with low-income customer assistance programs and other public policy driven initiatives through a societal benefits charge; costs associated with the restructuring-related buyout/by-down of non-utility generation contracts and other regulatory asset balances are recovered through non-by-passable charges.

New Mexico

Environmental Compliance--An SO_2 rider is in place for Public Service Co. of New Mexico through which customers are credited with their share of revenues from allowance sales.

Other--All of the utilities have a mechanism in place to recover variations in certain taxes and franchise fees.

New York

Electric Fuel/Gas Commodity/Purchased Power--Historically, all energy utilities used an electric fuel adjustment clause (FAC). With electric industry restructuring, however, generation was divested, and the electric companies have largely transitioned from the FAC to a market power adjustment clause (MAC) or a commodity adjustment clause (CAC). The MAC/CAC allows the distribution utilities to flow through the costs of power procured to serve customers who have not selected an alternative supplier.

North Carolina

Decoupling--State law authorizes the NCUC to approve an annual rider outside of a general rate case for electric utilities to recover all reasonable and prudent costs incurred for the adoption and implementation of demand-side management (DSM) and energy efficiency (EE) programs. The NCUC has authorized the major electric utilities to retain a percentage of the net savings associated with their DSM/EE programs.

Piedmont Natural Gas utilizes a Margin Decoupling Mechanism/Tracker that decouples the recovery of authorized margins from sales levels. Public Service Company of North Carolina also has such a mechanism in place.

Renewables Expense--Costs incurred by electric utilities to procure renewable energy are recoverable through the fuel clause and the renewable energy portfolio standard (REPS) rider subject to certain caps. The avoided cost is recoverable through the fuel adjustment clause (FAC), and payments in excess of the avoided cost are recoverable through the annual REPS rider. Incremental operation and maintenance costs and annual research and development (R&D) expenses up to $1 million are also recoverable through the REPS rider. The cost of utility-owned renewable generating facilities is recovered through a combination of the FAC, the REPS rider, and base rates.

Environmental Compliance--The costs of certain re-agents (e.g., limestone) used in reducing or treating electric power plant emissions may be recovered through the fuel adjustment clause.

Generic Infrastructure--Piedmont Natural Gas uses an integrity management rider that allows the company to track and recover capital expenditures incurred to comply with federal pipeline safety and integrity requirements outside of a general rate case.

North Dakota

Decoupling--MDU Resources' (MDU's) gas operations are subject to a weather normalization adjustment mechanism that is in effect for the winter heating season from Nov. 1 through May 1. Northern States Power-Minnesota (NSP-M) operates under straight fixed-variable gas rates.

Generation Capacity--MDU uses under a generation resource recovery rider through which it recovers costs associated with the 88-MW, simple cycle gas turbine Heskett III facility, which achieved commercial operation in August 2014.

Environmental Compliance/Generic Infrastructure--The electric utilities are permitted to earn a cash return on construction work in progress through a separate rate adjustment mechanism for investments in transmission infrastructure and for federally-mandated environmental compliance projects. Once the facilities achieve commercial operation, they are reflected in rate base as part of a general rate proceeding, and the surcharge terminates. MDU and Otter Tail Power (OTP) are operating under separate transmission and environmental cost recovery riders. NSP is operating under a transmission cost recovery rider.

Other--Through NSP-M's fuel and purchased power adjustment (FPPA) clause, the company shares equally with ratepayers prospective "non-asset-based" wholesale power margins (WPMs). Through its FPPA clause, OTP allocates prospective asset-based WPMs on an 85%/15% basis to ratepayers and shareholders, respectively.

Ohio

Electric Fuel/Gas Commodity/Purchased Power/Generic Infrastructure/Other--As a result of electric industry restructuring, the utilities operate under electric security plans (ESPs) that provide for the pass through of the utilities' cost of power to serve standard-service-offer customers.

The current ESPs for Cleveland Electric Illuminating, Ohio Edison, and Toledo Edison include delivery capital recovery riders that reflect a return of, and on, incremental distribution, sub-transmission, and general plant-in-service investments not already included in the companies' base rates.

Under Duke Energy Ohio's (DEO's) current ESP, the company's generation requirements for non-switching customers are procured and priced through a competitive bid process (CBP). Rider RC (retail capacity) and Rider RE (retail energy) are in place, both of which are fully bypassable for switching customers.

Ohio Power's (OP's) ESP allows the company to continue to utilize riders for costs related to distribution investment, enhanced service reliability, and storm damage recovery. OP also utilizes a deferred asset recovery rider, through which the company is to fully recover certain regulatory assets over the seven years, 2012 through 2018.

Dayton Power and Light's (DP&L's) ESP, adopted in 2013, includes a Service Stability Rider to permit the company to maintain its financial health and to have an opportunity to earn a reasonable return on equity. DP&L also uses an Infrastructure Investment Rider for recovery of costs related to advanced meter infrastructure and/or SmartGrid deployment.

East Ohio Gas (EOG), Columbia Gas of Ohio (CGO), and Vectren Energy Delivery of Ohio (Vectren) conduct auctions for competitive suppliers to bid to directly serve customers. The companies had previously obtained their gas supplies through negotiated bilateral contracts, but under the current plan, the companies conduct an auction that allows suppliers to compete to supply portions of the gas supply requirements. Customers who do not choose a specific competitive supplier are randomly assigned a supplier based on the auction results. DEO is the only major gas utility in the state to continue to use the gas cost recovery clause.

Decoupling/Conservation Program Expense--The ESPs for each of the Ohio electric utilities include a rider that allows for recovery of energy efficiency program costs and lost distribution margin associated with these programs. In 2011, the Ohio PUC approved a full pilot decoupling mechanism for OP residential and small commercial customers for calendar-years 2012, 2013, and 2014. In its February 2015 order in OP's ESP proceeding, the Commission permitted the company to continue to use the decoupling mechanism. Ohio's gas distribution companies, namely EOG, CGO, Vectren, and DEO all operate under straight fixed-variable prices.

Generic Infrastructure--CGO has a rider in place for infrastructure replacement costs. Vectren has a rider in place through which it recovers the costs associated with an accelerated main and service line replacement program. EOG has a pipeline infrastructure replacement cost recovery mechanism in place. DEO uses an Accelerated Main Replacement Program rider to recover the costs associated with its gas delivery infrastructure improvement program.

Other--All of the utilities have a mechanism in place to recover variations in certain taxes and fees. DEO uses Rider Manufactured Gas Plant (MGP) to recover PUC-approved costs associated with the company's environmental remediation of MGP sites.

Oklahoma

Conservation Program Expense/Decoupling--Oklahoma Gas & Electric (OG&E) and Public Service Oklahoma (PSO) utilize riders to recover the costs associated with energy efficiency programs, the related "lost revenues," and certain "incentives." CenterPoint Energy Resources (CER) and Oklahoma Natural Gas (ONG) recover the costs associated with energy efficiency programs through their performance-based ratemaking plans (ONG is not authorized to recover the related lost revenues.) CER and ONG also utilize weather normalization mechanisms.

Environmental Compliance/Other--Oklahoma Corporation Commission (OCC) rules permit the OCC to approve requests to recover costs associated with environmental compliance costs through a surcharge/rate rider. OG&E's storm cost recovery rider includes provisions that require a credit to ratepayers for the Oklahoma-jurisdictional portion of net revenues received from the sale of SO_2 credits.

Generation Capacity--OG&E utilizes a rider to recover the revenue requirement associated with the company's Crossroads Wind Farm, which was completed in 2012; the rider is to remain in place until new base rates are implemented. OG&E is to flow through to ratepayers, during the period the rider is in place, 100% of the proceeds associated with the sale of the renewable energy credits that accrue from the plant's operation.

Generic Infrastructure--OG&E utilizes a rider to recover the costs associated with the company's Smart Grid program. In addition, OG&E is permitted to recover costs (both capital- and expense-related) associated with the company's "system hardening" and "vegetation management" programs, through a rider. PSO utilizes a rider for recovery of incremental vegetation management, under-grounding costs, and system-hardening/grid resiliency costs.

Other--OG&E uses a storm-cost recovery rider to reflect any differences between the level of storm costs reflected in base rates and the level of such costs actually incurred in a given year. Ratepayers' share of OSS margins flow through PSO's fuel cost adjustment rider. OCC rules permit the Commission to allow utilities to recover security/safety-related costs through a surcharge/rate rider. (OG&E has such a rider in place.) OG&E, PSO, CER, and ONG have a mechanism in place to recover variations in certain taxes and franchise fees. ONG has a rider in place for costs related to lost, used, and unaccounted-for gas.

Oregon

Electric Fuel/Gas Commodity/Purchased Power--Portland General Electric (PGE), PacifiCorp, and Idaho Power (IP) are permitted to annually adjust rates to reflect forecasted power costs. PGE's and IP's power cost adjustment mechanisms include a component under which a portion of the difference between actual and forecasted power costs is deferred for future recovery or refund.

Decoupling--An electric revenue decoupling mechanism is to be in effect for Portland General Electric (PGE) until year-end 2016. The mechanism is designed to provide for the recovery of the revenue shortfall resulting from reduced consumption patterns associated with residential and certain commercial customers' conservation efforts.

Northwest Natural Gas (NWNG) uses a decoupling mechanism designed to counteract the impact on revenues of changes in average residential and commercial customers' consumption patterns due to conservation efforts. The company has a separate weather-adjusted rate mechanism (WARM) in place for these customers. Cascade Natural Gas (CNG) has a decoupling mechanism in place until Dec. 31, 2015, that adjusts for both conservation-related-demand reductions and deviations from normal weather. In a small pending rate case, CNG is seeking to continue to utilize a decoupling mechanism.

Renewables Expense--In accordance with state law, renewable resource adjustment clauses are utilized by the electric utilities for the recovery of prudently incurred costs associated with meeting the state's renewable energy standards. The mechanism allows for cost recovery, without filing a general rate case, of renewable resources that are expected to be placed into service in the current year.

Environmental Compliance--NWNG utilizes a site remediation and recovery mechanism to provide for recovery of costs incurred, and that continue to be incurred, for environmental remediation of legacy manufactured gas plant operations.

Generic Infrastructure--Until Oct. 31, 2014, NWNG utilized a System Integrity Program (SIP) related to the replacement of bare steel, pipeline integrity, and other pipeline safety programs, with recovery through the PGA after the first $4 million of capital costs were incurred by the company. The recovery of SIP costs was subject to a cost recovery cap of $37.7 million. NWNG proposed to extend the SIP with modifications, and in March 2015, the PUC suspended the request and instead opened a generic investigation to examine the recovery of safety costs by natural gas utilities.

Pennsylvania

Electric Fuel/Purchased Power/Gas Commodity/Renewables Expense--Historically, electric utilities were permitted to recover fuel and purchased power costs through a semi-automatic adjustment mechanism, the Energy Cost Rate (ECR); however, in conjunction with electric industry restructuring, the ECR was eliminated. Generation required to meet provider-of-last-resort (POLR) obligations for each company is competitively procured and priced. Renewable resource requirements are included in this process. Prices for POLR service are adjusted on a current basis as each procurement occurs.

Decoupling--Columbia Gas of Pennsylvania (CGP) has a weather normalization adjustment in place for residential customers.

Generic Infrastructure--State law allows the Pennsylvania PUC to approve automatic adjustment clauses to recognize, between general rate cases, utility investments in certain infrastructure projects. Distribution System Improvement Charges (DSICs) have been approved for CGP, PECO Energy 's (PECO's) gas operations (implementation of a DSIC is an issue in PECO's pending electric rate case), PPL Electric Utilities (PPL-E), Peoples Natural Gas, and Equitable Gas, UGI Central Penn Gas, and UGI Penn Natural Gas.

Other--All of the utilities have a mechanism in place to recover variations in certain taxes and franchise fees. PECO recovers nuclear decommissioning costs through a rider. PPL-E recovers universal service program costs through a rider.

Rhode Island

Electric Fuel /Gas Commodity/Purchased Power--Prior to the implementation of electric industry restructuring in 1998, automatic electric fuel adjustment clauses were used by the utilities. In accordance with the restructuring law and Rhode Island PUC-approved restructuring plans, investor-owned utilities are to provide standard offer service to customers who do not select an alternative provider through 2020. The cost of providing this service is fully recoverable, with such rates reset on a periodic basis.

Conservation Program Expense/Environmental Compliance--Narragansett Electric (NE) utilizes an annual distribution adjustment clause (DAC) for its gas operations to recover costs associated with demand-side management and environmental response.

Decoupling--Full revenue decoupling mechanisms are in place for NE's electric and gas operations.

Generic Infrastructure--State law permits NE to submit, for PUC approval, annual infrastructure spending plans for its electric and gas operations, and recovery of expenses associated with an inspection and maintenance program and vegetation management program.

Other--A pension adjustment mechanism is in place for NE's electric and gas operations that reconciles actual pension and other-post-employment-benefits expense to the level reflected in base rates. NE recovers electric commodity-related uncollectibles, including associated administrative costs, through its standard offer service rate. In addition, the company recovers transmission-related bad debt through a transmission-related uncollectible mechanism. NE reflects credits associated with margins from non-firm sales and transportation, earnings sharing, and service quality adjustments through the DAC.

South Carolina

Decoupling--Weather normalization adjustments are in place for South Carolina Electric & Gas (SCE&G) (gas operations) and Piedmont Natural Gas that apply to residential and small commercial customers.

Environmental Compliance--Emissions allowance costs and the cost of certain materials used in reducing or treating electric power plant emissions are reflected in the fuel clause.

Generation Capacity--Statutes allow the South Carolina PSC to issue a base load review act (BLRA) order, which constitutes an upfront determination that a plant is "used and useful," and that associated proposed capital expenditures are prudent and ultimately should be reflected in rates as long as the plant is constructed within the estimated construction schedule, including contingencies, and capital budget. For nuclear plants only, if requested by a utility, the BLRA order is to specify initial revised rates reflecting the utility's pre-construction and development costs. At least one year after its filing of a BLRA application, and no more frequently than annually thereafter, the utility is permitted to file for PSC approval of revised rates reflecting a cash return on a nuclear plant's construction work in progress (CWIP). The PSC has issued a BLR order for SCE&G's two-unit expansion of its V.C. Summer nuclear plant, and the company is currently earning a cash return on the plant's CWIP.

South Dakota

Conservation Program Expense/Decoupling--A demand-side management (DSM) cost adjustment mechanism is in place for Northern States Power-Minnesota (NSP-M) through which the company recovers costs associated with DSM/efficiency programs. The mechanism includes a 30% bonus to account for lost margins related to DSM/efficiency measures. Black Hills Power (BHP) operates under an efficiency adjustment rider through which the company recovers the cost of its energy efficiency programs, as well as any lost revenues (excluding the effects of weather) associated with the programs.

Generation Capacity/Generic Infrastructure--NSP-M utilizes an infrastructure rider to recover costs associated with certain capital additions (only after the items have achieved commercial operation) and to reflect certain changes in property taxes.

Other--Through its fuel and purchased power adjustment clause (FPPAC), BHP credits ratepayers a portion of the margins from renewable energy credit sales and power marketing income (PMI). NSP-M operates under certain wholesale power margin sharing provisions, and allocates ratepayers' share of any such margins through its fuel clause. NSP-M also credits ratepayers a portion of revenues generated from renewable energy credit sales through its fuel clause.

Tennessee

Decoupling--Weather normalization adjustment (WNA) clauses are in place for Atmos Energy and Piedmont Natural Gas (PNG). A full revenue decoupling mechanism was to be place through May 2013 for Chattanooga Gas' (CG's) residential and small commercial customers; however, in June 2013, the TRA authorized CG to continue operating under the mechanism while it reviews the company's petition to extend the rider. A WNA rider is also in place for CG's industrial, commercial, and other customers that do not operate under the decoupling mechanism.

Other-- Kingsport Power has a storm damage rider in place. Atmos Energy, PNG, and CG utilize riders related to capacity management and release, off-system sales, capacity assignment.

Atmos and CG operate under riders through which the companies share with ratepayers gross profit margin reductions associated with large industrial or commercial customers that are served under negotiated contracts and are able to bypass the utilities' distribution system. Through its purchased gas adjustment rider, PNG recovers margin losses associated with bypassable customers being served under negotiated contracts.

Texas PUC

Electric Fuel/Purchased Power--For companies that implemented retail competition, i.e., within the Electric Reliability Council of Texas (ERCOT), the transmission and distribution utilities do not have provider-of-last-resort/standard-offer-service obligations. Retail electric providers offer generation service at marked-based rates.

For electric utilities that have not implemented retail competition, fuel and purchased power costs are recovered through a separate fuel factor, the level of which is established in base rate cases. Between base rate cases, the fuel factor may be adjusted, following hearings, based on projected fuel costs for the period the fuel factor will be in effect, subject to true-up.

Conservation Program Expense--Electric distribution utilities are permitted to request recovery of costs associated with legislatively mandated energy efficiency programs through a streamlined adjustment mechanism. AEP Texas Central (TXC), AEP Texas North (TXN), CenterPoint Energy Houston (CEHE), El Paso Electric (EPE), Entergy Texas (ETI), Oncor Electric Delivery, Southwestern Electric Power (SWEPCO), Southwestern Public Service (SWPS), and Texas-New Mexico Power (TNMP) each have such mechanisms in place.

Generic Infrastructure--The PUC may approve periodic distribution cost recovery factors (DCRFs) for both vertically integrated and transmission and distribution-only electric utilities. The PUC may prohibit a utility from implementing a rate change under the mechanism if the Commission determines that the utility is earning in excess of its authorized return prior to the adjustment. Amounts approved for recovery under the DCRF are to be rolled into base rates in the utility's subsequent rate case. A DCRF was approved for ETI in 2014, and for CEHE in August 2015.

State law permits the utilities to recover costs associated with deployment of advanced metering technology through a separate surcharge, and the PUC has for the most part approved such mechanisms when requested. Advanced metering surcharges are in place for TXC, TXN, CEHE, Oncor, and TNMP.

For the service territories in which retail competition has been implemented (i.e., within ERCOT), transmission service providers are permitted to file up to twice annually, outside of a base rate case, to implement rate changes to reflect new transmission facilities through an interim transmission cost-of-service mechanism (TCOS). TCOS mechanisms have been approved for TXC, TXN, CEHE, Oncor, and TNMP, as well as transmission-only entities such as Cross Texas Transmission, Electric Transmission Texas, Lone Star Transmission, and Wind Energy Transmission of Texas.

Utilities that have not implemented retail competition (EPE, ETI, SWEPCO, SWPS) may file between rate cases (limited to once annually) for adjustments to reflect new investment in transmission facilities. This procedure is known as a transmission cost recovery factor (TCRF) mechanism.

RTO-Related Transmission Expense--Transmission revenue requirements established through either base rates or the TCOS procedure are allocated among the distribution service providers (DSPs) within ERCOT based on PUC-approved, load-based allocation factors, established under the Commission's "transmission matrix." The DSPs are permitted to adjust rates charged to REPs twice annually to reflect changes in wholesale transmission costs assigned to the DSP by ERCOT. These changes flow through a mechanism also known as a TCRF, which is in place for CEHE, Oncor, TNMP, TXC, and TXN.

Other--The PUC has, at various times, approved riders (for ETI and TNMP) for recovery of extraordinary storm costs that had been deferred, with recovery to occur over a multi-year period. RRA does not consider this treatment to be an adjustment clause per se. In other cases, the PUC has approved a rider that allows for recovery of variations in storm costs versus the level included in base rates. Such a rider is in place for ETI. CEHE, ETI, and TNMP have adjustment clauses in place to reflect changes in municipal franchise fees. EPE has a rider in place to recover lost revenue associated with the provision of discounted service to military bases, while SWPS recovers lost revenue associated with the provision of discounts to state universities through a rider.

Texas RRC

Gas Commodity Costs--Purchased gas cost adjustment clauses may be implemented under certain circumstances. Specifically, the RRC must consider: (1) the ability of the pipeline or local distribution company to control prices for gas purchased, in light of competition and relative competitive advantage; (2) the probability of frequent price changes; and, (3) the availability of alternative gas supply resources. In the context of a 2004 rate decision for Atmos Energy (Atmos), the RRC approved the implementation of a gas cost recovery factor to reflect gas commodity cost changes that occur between rate cases. A similar mechanism is in place for Texas Gas Service (TGS).

Decoupling--Weather normalization adjustments are in place for Atmos and TGS.

Generic Infrastructure--Surcharge mechanisms for gas reliability infrastructure program (GRIP) costs are in place for CenterPoint Energy Resources' Houston and South Texas Divisions. A similar mechanism is in place for most of the cities served by Atmos Energy's Mid-Tex and West Texas Divisions. Operations in the City of Dallas and its environs (part of the Mid-Tex Division) are subject to a "Dallas Annual Rate Review Mechanism" that takes into account several factors including new infrastructure investment. An annual cost-of-service adjustment mechanism (similar to the Rate Review Mechanism) is in place for TGS.

Other--Gas-commodity-related uncollectibles are recovered through Atmos' GCRF.

Utah

Decoupling--A weather normalization adjustment (WNA) is in place for Questar Gas; however, customers may elect not to participate in the WNA. Questar Gas also utilizes a conservation-enabling tariff (CET), which decouples non-gas revenues from the volume of gas used by general service (GS) customers. Under the CET, a margin-per-customer target is specified for each month, with non-weather-related differences to be deferred and recovered from, or refunded to, GS customers via periodic rate adjustments. Annual CET accruals are limited to 5% of base distribution non-gas (DNG) revenues, and the amortization of CET accruals is limited (on a net basis) to 2.5% of total Utah-jurisdictional base DNG GS revenues. Together, the WNA and CET act as a full revenue decoupling mechanism.

Renewables Expense--PacifiCorp operates under a renewable energy credit (REC) mechanism that tracks variations in REC revenues from a base level established in the most recent general rate case, with any differences to flow to customers via an annual credit or surcharge. Separately, an adjustment mechanism is in place for PacifiCorp through which the company recovers costs associated with its solar program.

Generic Infrastructure--A pilot infrastructure replacement adjustment mechanism is in place for Questar Gas that permits the company to recover, between rate cases, the incremental costs associated with the replacement of high-pressure natural gas feeder lines. The mechanism is to be adjusted at least annually, and has an annual budget cap of $65 million.

Other--Questar Gas flows ratepayers' share of its capacity release revenue to customers via its semi-annual gas-cost pass-through proceedings.

Vermont

Decoupling--We note that alternative regulation plans in place for Green Mountain Power and Vermont Gas Systems somewhat obviate the need for revenue decoupling mechanisms, as the plans allow for annual rate adjustments based on the company's forecast of sales and costs, and contain earnings-sharing provisions that minimize losses if sales fall significantly from forecast.

Virginia

Electric Fuel/Purchased Power--Energy and capacity charges for "economy" purchases are included in the electric fuel factor calculation. Energy charges associated with reliability purchases may flow through the fuel factor; but capacity charges are recovered through base rates.

Conservation Program Expense--State law permits the SCC to approve rider mechanisms for the recovery of utilities' conservation and energy efficiency program costs. Such mechanisms are in place for Virginia Electric Power (VEPCO), Appalachian Power (APCO), and Columbia Gas of Virginia (CGV).

Decoupling--A Weather Normalization Adjustment (WNA) rider is in place for Virginia Natural Gas (VNG) and Washington Gas (WG). A revenue normalization adjustment (decoupling) mechanism is in place that is designed to mitigate the impact on Washington Gas (WG's) and CGV's revenues of customers' participation in energy conservation programs.

Environmental Compliance/Generation Capacity--State statutes permitted the electric utilities to seek SCC approval to begin recovering costs associated with environmental compliance and reliability improvement programs through an Environmental & Reliability Factor (ERF). Such a mechanism was in place for APCO from 2006 through 2011. APCO now has an environmental compliance rate adjustment clause in place. State law allows the SCC to approve riders to achieve rate recognition of investment in new generation facilities, including a cash return on construction work in progress and an incentive return-on-equity premium for certain types of facilities for a portion of their useful lives. The SCC has approved such riders for both VEPCO and APCO.

Generic Infrastructure--Legislation enacted in 2014 authorizes the SCC to approve annually adjusted riders for the recovery of cost/investments (including a cash return on construction work in progress) associated with utility projects to replace existing overhead distribution facilities of 69 kilovolts or less located within the Commonwealth with underground facilities. Investments recognized through an approved rider would be capped at 5% of the utility's total distribution rate base as determined in the most recently decided a biennial review proceeding at the time the adjustment is requested. Investment excluded from the rider would be deferred and would be eligible for recovery through a base rate proceeding. The rider's revenue requirement would reflect the rate of return approved in the company's most recent base rate case or biennial review proceeding.

The SCC may also allow a natural gas utility that invests in natural gas facility replacement projects to recover, in the form of a rider, a return on investment, a revenue conversion factor, depreciation, property taxes and carrying costs on over/under recovery of the related costs. Eligible infrastructure replacement is defined as natural gas facility replacement projects that (i) enhance safety or reliability by reducing system integrity risks associated with customer outages, corrosion, equipment failures, material failures, or natural forces; (ii) do not increase revenues by directly connecting the infrastructure replacement to new customers; (iii) reduce or have the potential to reduce greenhouse gas emissions; (iv) are commenced on or after Jan. 1, 2010; and (v) are not included in the natural gas utility's rate base in its most recent rate case. Such riders have been approved for VNG, WG, and CGV.

Other--WG and CGV are permitted to recover carrying charges on storage gas balances and over/under-collected gas costs, hexane costs, and commodity-related uncollectibles expense through an adjustment mechanism. APCO and VEPCO have a mechanism in place to recover variations in certain taxes and franchise fees.

Washington

Electric Fuel/Gas Commodity/Purchased Power--An Energy Recovery Mechanism (ERM) is in place for Avista that allows the company to adjust electric rates to reflect changes in power supply-related costs, with a graduated sharing of differences from a benchmark level. A power cost adjustment mechanism (PCAM) is in place for Puget Sound Energy (PSE) that allows for variations in power costs to be apportioned, on a graduated scale, between the company and customers.

Decoupling--Revenue decoupling mechanisms are in place for PSE's electric and gas operations, in conjunction with a rate plan that is to provide for annual increases in allowed revenue per customer for the duration of the rate-plan period (through at least March 2016 and possibly through March 2017).

In November 2014, the WUTC adopted full decoupling mechanisms for Avista's electric and gas operations, effective Jan. 1, 2015. The mechanisms are to: be in place for five years; be evaluated every three years; and, incorporate an earnings test and demand-reduction targets. In addition, surcharge increases under the mechanisms are capped at 3%, with unrecovered balances carried forward to future years; decoupling surcredits are not subject to a cap.

New Capital Investment--The WUTC has approved two-year pipeline replacement plans for PSE, Avista, Cascade Natural Gas (CNG) and Northwest Natural Gas (NNG) for the 2013-2015 period. CNG and PSE utilize riders for the costs associated with their plans. Avista and NNG did not seek such a mechanism.

West Virginia

Environmental Compliance/Generation Capacity/Generic Infrastructure--In 2006, the West Virginia PSC established a temporary rider mechanism for Appalachian Power (APCO) and Wheeling Power to recover the costs/investment in certain transmission expansion and environmental compliance projects. These investments are now reflected in base rates. In 2008, the PSC approved a similar mechanism for an integrated coal gasification combined-cycle plant proposed by APCO to serve both West Virginia and Virginia, but the project was tabled after the Virginia SCC rejected the plant.

Other--The utilities have mechanisms in place to recover variations in certain taxes and franchise fees.

Wisconsin

Electric Fuel/Gas Commodity/Purchased Power--Under the Wisconsin PSC's electric fuel rules, which apply to the state's five largest investor-owned utilities, each utility forecasts monthly and annual fuel and purchased power costs on a prospective basis. If a company's actual fuel and purchased power costs are outside a monthly or cumulative monthly variance range around the forecasts, and the utility can demonstrate that these costs will likely be outside the annual range, the PSC may conduct a hearing to establish new rates. Currently, the annual variance range is plus or minus 2%. An electric utility is permitted to defer any fuel costs that are outside of its annual, symmetrical variance range for subsequent recovery or refund. However, the utility is prohibited from recovering deferrals if the company is found to be earning in excess of its authorized equity return.

Generation Capacity/Generic Infrastructure/Other--At times, the PSC has authorized the utilities to file a limited issue reopener (LIR) of a previously completed base rate case instead of a full rate case. The LIR provides for recognition of certain specified investments and/or expenses, and does not involve the re-determination of rate of return.

Other--All of the utilities have a mechanism in place to recover variations in certain taxes and franchise fees.

Wyoming

Decoupling--SourceGas Distribution has a partial decoupling mechanism in place for small and medium general service class distribution customers. The mechanism does not address revenue variations due to weather. Cheyenne Light Fuel & Power's (CLF&Ps) demand side management (DSM) mechanisms for its electric and gas operations include provisions that provide for the recovery of "lost margins" associated with customer participation in the DSM programs.

Renewables Expense/Environmental Compliance--Optional renewable energy riders are in place for CLF&P, MDU Resources Group, and PacifiCorp. PacifiCorp operates under an adjustment mechanism that is designed to recover from or refund to ratepayers 100% of difference between actual renewable energy and SO_2 emissions allowance credit revenue levels and the levels reflected in base rates.

Other--Through an incentive provision of its fuel clause, CLF&P allocates a portion of off-system sales margins to ratepayers.

EXHIBIT
UNSE-38
admitted

NEW RATE STRUCTURE

A Cooperative Partnership with you... our members.

MCEC is implementing a NEW rate structure that gives members more control over their power bill than ever before!

By simply reducing energy use during the highest cost period each day, members can save on power bills.

We are proud of the partnership with our members that goes back over 75 years...

and we are even more excited to partner with you towards the future! The energy landscape and technology has been changing rapidly, but one thing will remain the same—our commitment: to provide our members quality electric services at competitive costs.

As a cooperative, our business model is different—we are member-owned. As you pay your electric bill over time, you receive funds back in the form of capital credits. Each decision we make is made with our members in mind and how we most equitably go forward into the future together. Click here to view the letter mailed to all members, or here to view an informative brochure.

A new way of looking towards the future:

We are embracing a new rate structure that will allow us to continue to provide you with energy at reasonable costs. After a great deal of study, we have determined that this rate structure will allow us to best serve all members in the fairest way possible both now and in the future.

What are the different parts of the new rate structure?

• **Account charge**. The cost of making service available to our members. It recovers the cost of making service available to each member.

• **Energy charge**. Energy is the number of kilowatt-hours used by the member over the billing period. Based on your individual meter reading, this is the number of units you are used to seeing each month on your bill. The energy charge is equal to the kilowatt-hours used multiplied by the energy rate. In this new structure, we have been able to lower the charge per kilowatt-hour from about 11.5¢ to 4.7¢.

(kWh) – One kilowatt-hour is defined as the amount of energy consumed by a 1000-Watt appliance running continuously for 1 hour.

• **On-Peak charge**. To determine the On-Peak charge (traditionally known as a demand charge), the highest ONE hour of energy use is identified from the On-Peak hours in each billing period. That ONE hour is billed at the On-Peak charge per kW.

(kW) – One kilowatt is defined as the amount of power required to operate a

1000-Watt appliance.

Click here for a more in depth explanation of how demand effects the on-peak charge.

What are the On-Peak hours?

On-Peak is defined as the hours during the day when electricity is most used and when power is more expensive.

From November 1 to March 31,
the Winter On-Peak hours are from 6 a.m. to 9 a.m.
When it's cold, power is more expensive in the morning as people are preparing to go to work.

From April 1 to October 31,
the Summer On-Peak hours are from 4 p.m. to 7 p.m.
When it's hot, power is more expensive in the evening when people get home from work.

What are the financial costs of the new rate structure?

There are THREE main categories of cost incurred by our system by residential and commercial members:

1. Account charge Residential 80¢/day Commercial $1.10/day
This recovers the cost of making service available to each member.

2. Energy charge Residential 4.7¢/kWh Commercial 5.7¢/kWh
This is the energy portion of the power cost.

3. On-Peak charge Residential $12/kW Commercial $14.75/kW
This is the rate for the highest ONE hour of electric use during the On-Peak time frame of the billing period.

When will this new rate structure take effect?

Bills rendered beginning February 1, 2016, will reflect use during the previous month of January.

Why a new rate structure?

We now have the technology in place that will allow us to charge a more accurate fee for electric use and recover costs from members as they occur in the system. Rates should be cost-based so that members in each rate class pay their fair share of the total costs.

The Effect Of The New Rate Structure On You... Our Members.

What does this mean for your account?

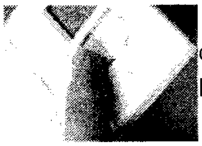
It depends on your use habits—for most members, you won't see a change. However, in all cases you have a choice and control over how you use energy.

How can you affect your power bill?

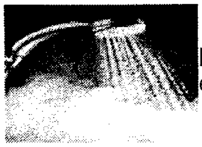
There are many ways that you can control your overall power bill. One way would be to examine your energy use habits and understand when are the most expensive hours to consume energy, On-Peak. Consider how you can save money on your power bill by minimizing energy use during On-Peak hours and help the co-op as well.

What can you do to cut down on energy use during the On-Peak hours?

These are just a few examples of some simple changes that can help you save money:



• Manually adjust your thermostat so that your HVAC runs less during the On-Peak hours. Consider investing in a programmable thermostat.



• Limit hot water use during the On-Peak hours and consider placing a timer on your hot water heater that helps shift the energy load.

• Use your dryer, oven or other high-use appliances before or after the On-Peak hours.

Click here for a list of appliances and the amount of energy they use. For more energy-saving tips, please visit our website, http://www.mcecoop.com/content/energy-tips (http://www.mcecoop.com/content/energy-tips) or request our energy-saving tips brochure.

MCEC Is Committed To Our Members And Our Community.

While power prices are up nationwide, as a not-for-profit electric cooperative, we will continue to do everything we can to manage costs and provide the same reliable service as always at the lowest possible cost.

We have been analyzing meter data reflecting more than 10 years of hourly demand (kW) which allows us to understand our true power costs. We have the technology in place to accurately determine your On-Peak use which allows these costs to be equitably allocated among all members. We are excited about the new possibilities that this will provide each member of Mid-Carolina Electric Cooperative in our ongoing partnership.

From the beginning, we were formed as a cooperative to make a difference—not only in the lives of individual members but also in our communities. That has always been and will remain our commitment here at MCEC.

Mid-Carolina Electric Cooperative. Your Trusted Energy Partner for 75 Years.

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As a cooperative, our business model is different—we are member-owned. You get a vote in our annual meetings, and as you pay your electric bill over time, you receive funds back in the form of capital credits. Each decision we make is made with our members in mind and how we most equitably go forward into the future together.

A new way of looking towards the future:

We are embracing a new rate structure that will allow us to continue to provide you with energy at reasonable costs—no matter its form. After a great deal of study, we have determined that this rate structure will allow us to best serve all members in the fairest way possible both now and in the future.

What are the different parts of the new rate structure?

- **Account charge.** The cost of making service available to our members. It covers the operating costs of the cooperative.
- **Energy charge.** Energy is the number of kilowatt-hours used by the member over the billing period. Based on your individual meter reading, this is the number of units you are used to seeing each month on your bill. The energy charge is equal to the kilowatt-hours used multiplied by the energy rate. In this new structure, we have been able to lower the charge per kilowatt-hour from about 11.5¢ to 4.7¢.

  (kWh) – One kilowatt-hour is defined as the amount of energy consumed by a 1000-Watt appliance running continuously for 1 hour.
- **On-Peak charge.** To determine the On-Peak charge, the highest ONE hour of energy use is identified from the On-Peak hours in each billing period. That ONE hour is billed at the On-Peak charge per kW.

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From April 1 to October 31,
the Summer On-Peak hours are from 4 p.m. to 7 p.m.
When it's hot, power is more expensive in the evening when people get home from work.

You now have the opportunity to lower your total power costs by reducing electricity use during these On-Peak hours each day.

What are the financial costs of the new rate structure?

There are THREE main categories of cost incurred by our system by residential and commercial members:

1. Account charge Residential 80¢/day Commercial $1.10/day	This is the cost to make electric service available to all members.
2. Energy charge Residential 4.7¢/kWh Commercial 5.7¢/kWh	This is the energy portion of the power cost.
3. On-Peak charge Residential $12/kW Commercial $14.75/kW	This is the rate for the highest ONE hour of electric use during the On-Peak time frame of the billing period.

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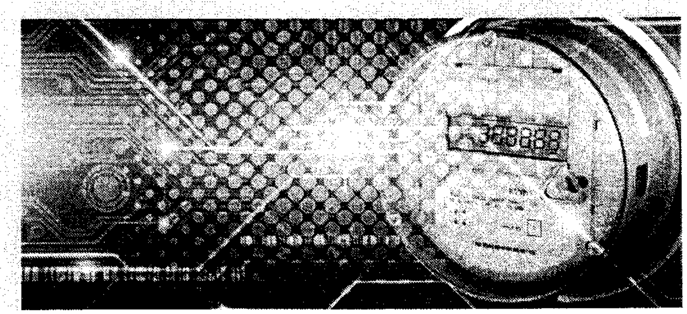

MCEC
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A Cooperative Partnership with you...our members

New Rate Structure for 2016

MCEC is implementing a new rate structure that gives members more control over their power bill than ever before! By simply reducing energy use during the highest cost period each day, members can save on power bills.

The rate has a new look!

1. **The account charge** replaces the basic facilities charge and is based on how many days of service are in the billing cycle. The account charge is 80¢ per day.
2. **The new energy charge** is much lower now. The current charge averages 11¢ for each kilowatt hour (kWh) used. The new charge is 4.7¢ per kWh. *(kWh) – One kilowatt-hour is defined as the amount of energy consumed by a 1000-Watt appliance running continuously for 1 hour.*
3. **The On-Peak charge is new.** This charge is based on the highest ONE hour of electricity use in the billing cycle during the On-Peak hours. The charge is $12 per kW in that one hour. *(kW) – One kilowatt is defined as the amount of power required to operate a 1000-Watt appliance.*

From November 1 to March 31, the Winter On-Peak hours are from 6 a.m. to 9 a.m.

[illegible], the Summer On-Peak hours are from 4 p.m. to 7 p.m.

A Sample Bill Comparison (NEW RATE STRUCTURE vs. Old Rate Structure)

NEW RATE STRUCTURE: There are 3 parts that are used to determine your monthly bill.

- **a. Account Charge:** Total days in the billing cycle, January 15 to February 13 — 30 days
- **b. Energy:** Energy Use from all days and all hours — 1355 kWh
- **c. On-Peak:** The highest ONE hour of electricity use during the On-Peak hours for the billing cycle — 6.4 kW

Account Charge	80¢ x 30 days	$ 24.00
Energy Charge	4.7¢ x 1355 kWh	$ 63.69
On-Peak Charge	$12 x 6.4 kW	$ 76.80
	Total Bill	$ 164.49

Basic Facilities	Per Billing Cycle	$ 19.00
Energy Charge	11¢ x 1355 kWh	$ 149.05
	Total Bill	$ 168.05

Old Rate Structure

How to Minimize On-Peak Use

Minimizing energy use during On-Peak hours can help lower your power cost.

Residential: You don't have to turn everything off but avoid using all appliances at the same time.

(For example, if you are cooking, drying clothes and the air conditioner is running, your On-Peak use can be higher. Consider running the dryer after the cooking is done or even better, after the On-Peak hours.)

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For more information and energy-saving tips visit www.mcecoop.com

Appliance	Watts Used	kW
Heat Strips/ Electric Furnace **	10,000	10
Clothes Dryer	5,000	5
Water heater	4,500	4.5
A/C Central 3 ton: 10 SEER	3,600	3.6
Oven (self cleaning)	3,200	3.2
Range cook top (large unit)	3,200	3.2
A/C Central 3 ton: 14 SEER	2,571	2.571
Deep Fryer	1,500	1.5
Electric Fireplace	1,500	1.5
Hair Dryer	1,500	1.5
Outdoor grill	1,500	1.5
Space heater per hour	1,500	1.5
Dishwasher (not incl.Hot Water)	1,500	1.5
A/C window 12,000 BTU 9 EER	1,333	1.333
Range cook top small unit	1,300	1.3
Coffee Maker	1,100	1.1
Pool pumps 1 hp	1,100	1.1
Toaster	1,100	1.1
Water well pump 1 hp	1,080	1.08
Iron	1,000	1
Microwave oven	1,000	1
Blender	720	0.72
Refrigerator 20 cu ft frost free	650	0.65
Vaccum Cleaner	650	0.65
Washing machine	500	0.5
Freezer 18 cu ft frostfree	400	0.4
Food processor	370	0.37
Fish pond pump	300	0.3
Dehumidifier	257	0.257
Yard flood light	250	0.25
Television	250	0.25
Electric Blanket	175	0.175
Slow cooker (high)	150	0.15
Ceiling fan	88	0.088
Yard High Pressure Sodium	75	0.075
Radio	75	0.075
Curling Iron	50	0.05
Shaver rechargeable	40	0.04
VCR/DVD player or Playstation	25	0.025

** An electric furnace will vary from 5 kw to 15 kW

The effect of the new rate structure on you... our members.

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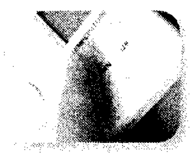

- Manually adjust your thermostat so that your HVAC runs less during the On-Peak hours. Consider investing in a programmable thermostat.

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A Cooperative Partnership *with you... our members.*

2016 Rate Structure

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UNS Electric, Inc. Rate Application
Docket No. E-04204A-15-0142
AURA Responses to UNSE's 1st Date Requests
January 12, 2016

Response provided by: Patrick Quinn

Title: Principal

Data Request Number: UNSE 1.1

Q. *Admit that the AURA has no legal existence separate from Quinn and Associates , llC. If your answer is anything other than an unqualified admission, provide a complete explanation and all supporting documents.*

A. Arizona Utility Ratepayer Alliance is a d/b/a of Quinn and Associates, LLC.

EXHIBIT
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UNSE-39
admitted

UNS Electric, Inc. Rate Application
Docket No. E-04204A-15-0142
AURA Responses to UNSE's 1st Date Requests
January 12, 2016

Response provided by: Patrick Quinn

Title: Principal

Data Request Number: UNSE 1.2

Q. *Admit that AURA is a d/b/a of Quinn and Associates, LLC. If your answer is anything other than an unqualified admission, provide a complete explanation and all supporting documents.*

A. See response to UNSE 1.1.

UNS Electric, Inc. Rate Application
Docket No. E-04204A-15-0142
AURA Responses to UNSE's 1st Date Requests
January 12, 2016

Response provided by: Patrick Quinn

Title: Principal

Data Request Number: UNSE 1.3

Q. *Please list each member of AURA who is customer of UNS Electric, Inc.*

A. There are no members of AURA that are customers of UNS Electric, Inc. This is also true of several other interveners in this rate case. Because of the timing of UNSE's rate cases filing, UNSE will be the first case to address many significant issues. These include rate design, how solar customers are charged and compensated for using the grid, along with many other issues. It was therefore necessary for AURA to intervene in this rate case.

UNS Electric, Inc. Rate Application
Docket No. E-04204A-15-0142
AURA Responses to UNSE's 1st Date Requests
January 12, 2016

Response provided by: Patrick Quinn

Title: Principal

Data Request Number: UNSE 1.4

Q. Mr. Quinn's testimony (Rate Design Direct, page 1) states that "The Arizona Utility Ratepayer Alliance was founded in 2015 to advise and represent utility ratepayers on vital issues affecting their pocketbooks." Please state who founded AURA and provide all organizational documents.

A. Patrick J Quinn founded the organization. All information requested in this data request has been gathered by UNSE and was included in their motion to oppose Arizona Utility Ratepayer Alliance's motion to intervene.

UNS Electric, Inc. Rate Application
Docket No. E-04204A-15-0142
AURA Responses to UNSE's 1st Date Requests
January 12, 2016

Response provided by: Patrick Quinn

Title: Principal

Data Request Number: UNSE 1.5

Q. *Mr. Quinn testifies (Rate Design Direct, page 2) that "Accordingly, AURA'S concerns lie primarily with aspects of the proposed rate design, which has historically been based on Commission, policies." Please provide copies of each Commission policy statement expressing the policies referenced by Mr. Quinn.*

A. It was the clear intent of Mr. Quinn's testimony, to point out that Commission rate case decisions are by their very nature expressions of Commission policies at the time of each decision, as determined by the elected Commissioners.

Past rate design proposals have had a basis in James C Bonbright's work "Principles of Public Utility Rates." NARUC summarized his principles as promoting the following elements:

- Simplicity, understandability, public acceptability and feasibility of application and interpretation
- Stability of rates themselves, minimal unexpected changes that are seriously adverse to existing customers
- Fairness in apportioning cost of service among different consumers
- Avoidance of "undue discrimination"
- Efficiency, promoting efficient use of energy and competing products and services

Bonbright states that rates should be cost-based, and that no unintentional subsidies should exist. While these provide a basis for determining rate design, the Commission has used this as a guide while incorporating their own policies. They have established rates for residential customers over the years that include cross-class subsidies. The Company filing stated that 70% of residential customers do not cover their fixed costs. If the Commission had been committed to eliminating cross subsidization over the years this would not be true.

Whether there are written policies or not, there are implied policies in the current rate design. For residential customers, rates have not generally been set at cost.

UNS Electric, Inc. Rate Application
Docket No. E-04204A-15-0142
AURA Responses to UNSE's 1st Date Requests
January 12, 2016

Response provided by: Patrick Quinn

Title: Principal

Data Request Number: UNSE 1.10

Q. *Provide the percentage of funding for AURA by: (1) residential ratepayers; and (2) solar industry groups.*

A. To date all funding comes from the Energy Foundation.

FreshProduce
ASSOCIATION OF THE AMERICAS

FOR IMMEDIATE RELEASE
February 02, 2016

FPAA Releases Nogales Import Report for Season 2014-15

View Full Report

Nogales, Ariz. (Feb. 2016) By volume, tomatoes remain the No. 1 produce item imported through Nogales, but watermelon imports have risen dramatically in recent years, and in the past season watermelon imports almost caught up to tomatoes, according to the The Nogales Produce Import Report 2014-15.

The Nogales Produce Import Report 2014-15 offers an analysis and comparison of three seasons of fresh produce's imports through Nogales in volume as well as value as reported to U.S. Customs.

"It is a tool we have developed to help our members understand the overall picture of fresh produce imports and see what their participation in the industry may be. It also may help them understand the tendencies and detect opportunities to explore," said Lance Jungmeyer, president of FPAA.

At the end of 2014-15 season, Nogales reported a total volume of 5.9 billion lbs. of fresh produce, this is a continued increase since the 2012-13 season. Approximately 89% of this volume is composed by only ten items and its different varieties, although there are over 50 different fruits and vegetables that make their way from Mexico into the country through this port to satisfy the growing demand.

	Volume by Season in 1,000 lbs.			Nogales Produce Mkt. Share in Volume		
By Item	2012-13	2013-14	2014-15	2012-13	2013-14	2014-15
Tomatoes	1,260,218	1,185,773	1,123,825	22%	20%	19%
Watermelons	905,850	1,033,015	1,111,168	16%	18%	19%
Cucumbers	683,213	756,229	784,527	12%	13%	13%
Squash	529,896	632,292	622,265	9%	11%	10%
Bell Peppers	578,142	558,752	571,723	10%	10%	10%
Grapes	289,949	299,617	314,994	5%	5%	5%
Mangos	215,680	134,600	215,092	4%	3%	4%
Chili Peppers	183,155	208,981	210,146	3%	4%	4%
Melons	211,857	215,877	226,801	4%	4%	4%
Eggplant	109,429	103,926	99,623	2%	2%	2%
Top 10 volume	**4,967,489**	**5,189,003**	**5,280,164**	**87%**	**89%**	**89%**

Note: The data collected includes volume and gross imported customs value, value declared at U.S. Customs for all fruits and vegetables and general information about the participation of the Nogales imports in the overall produce imports of the country. Customs value does not reflect the actual selling, or F.O.B., price of items.

2014-15 NOGALES PRODUCE IMPORT REPORT WWW.FRESHFROMMEXICO.COM 1

The report also shows a comparison in the volumes crossed by the main ports of entry of Mexican produce in the U.S.

Understanding the importance of the fresh produce trade happening in Nogales is not only a good tool in the decision making process of the companies involved, but it is also a reminder to the overall community of how crucial the port of Nogales is and has been in the supply of fruits and vegetables to the country, concluded Jungmeyer.

EXHIBIT
UNSG-40
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The report is available at www.freshfrommexico.com
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View Full Report

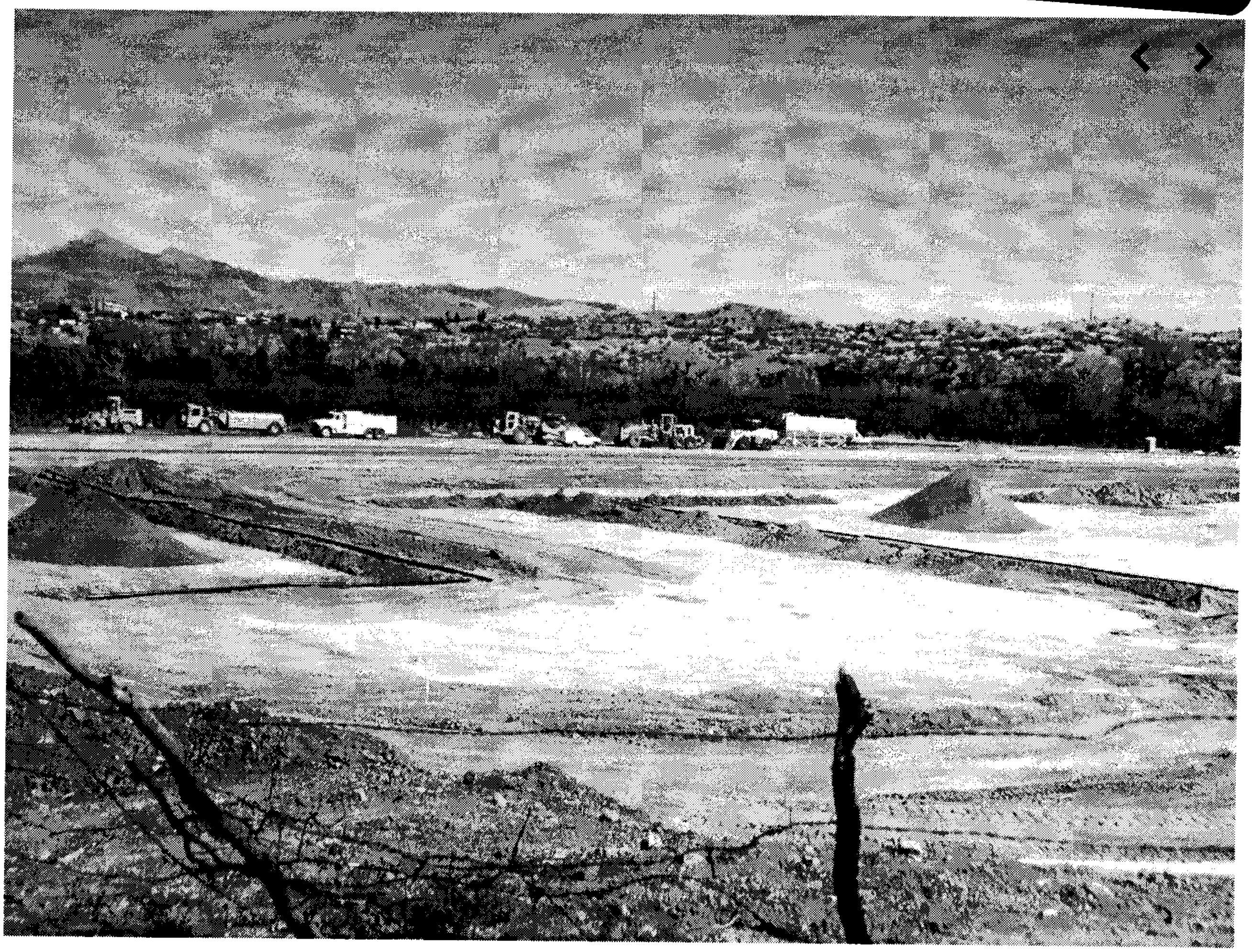
< Return to News List

http://www.nogalesinternational.com/news/large-warehouse-project-shows-need-for-infrastructure-to-match-growth/article_40c22be4-cb94-11e5-aee0-4bdf3f43ee70.html

Large warehouse project shows need for infrastructure to match growth

EXHIBIT
UNSE-41
admitted

By Murphy Woodhouse
Nogales International Feb 5, 2016



Paulina Pineda
Construction is under way at the site of the new warehouse east of Interstate 19 and south of Ruby Road.

Just east of Interstate 19 and south of Ruby Road, tractors and other heavy machinery are busy making way for what will be one of the largest commercial warehouses in Santa Cruz County.

Nora's Ranch Warehouse, which is being built by Delta Properties, will be around 191,500 square feet with another 17,000 or so square feet of office space. It is valued at just over $13 million.

The structure is going up in an area where low water pressure has frustrated fire officials in recent years and road infrastructure is often overwhelmed by waves of commercial truck and car traffic. While two local business authorities said the construction is a promising sign of economic development, the project also points to the additional public spending necessary to meet the infrastructure needs of new development.

Traffic at the Ruby Road interchange with I-19 just north of the warehouse site is already bad, said Guillermo Valencia, director of the Greater Nogales Port Authority. "What's going to happen with more traffic?" he asked rhetorically. "It's just going to get worse."

To put the warehouse's scale in context, its valuation exceeds the $11.7 million in all new commercial buildings and additions permitted last year in unincorporated areas of the county, according to county records previously provided to the NI. Roughly three-and-a-half football fields would fit inside the finished building, which will be approximately twice the size of the Del Campo cold storage facility on the other side of I-19.

What's more, there are more than 50 truck ports pictured in one of the warehouse blueprints.

The county issued a building permit for the warehouse on Jan. 20. Delta Properties purchased the warehouse's approximately 48-acre lot for $500,000 in late 2012, according to assessor records.

Dino Panousopoulous, owner of Delta Properties, said in an email that the new warehouse will be a "mixed-use facility with multiple occupants," whose construction was spurred by both the roughly $200-million expansion of the Mariposa Port of Entry and the prospect of expansion at the Port of Guaymas in southern Sonora.

"We hope both drive growth," Panousopoulous said.

Lance Jungmeyer, president of the Fresh Produce Association of the Americas (FPAA), and Valencia of the port authority said the new warehouse, as well as a number of others that have gone up in recent years, are a natural consequence of the federal government's investment in the Mariposa port.

"With the new investments in the port and some of the facilities we have, it's just going to draw more and more business to our corridor, to our region, to our community," Valencia said.

"The business is growing here in volume on a year-to-year basis and the companies are adapting in order to do that," Jungmeyer said.

While growing slower than some port cities in Texas, produce imports through Nogales between January 2015 and September 2015 were up nearly 15 percent over the same period the year before, according to Texas A&M University research previously provided to the NI. In addition, Jungmeyer said, the produce season is getting longer, putting more pressure on existing warehouse capacity.

"There are certain times of the year where the community far exceeds its capacity for warehouses," he said, adding that during recent peak seasons some companies simply stored watermelons and other produce in tractor-trailers because there was no available space.

ADOT approval

While itself a response to infrastructure investment, the new warehouse and others like it may require additional government expenditure to accommodate increased truck traffic, Jungmeyer and Valencia said.

Panousopoulous said that the Arizona Department of Transportation approved his facility's traffic plan and since existing traffic will be rerouted, he doesn't expect "much new traffic." He also said he believes ADOT considers the road infrastructure in the area "adequate."

An ADOT spokesman said that after the agency reviewed the warehouse's traffic impact analysis in 2014, it "approved plans" for Delta Properties to put in a "developer-funded southbound left-turn lane to mitigate traffic at the project intersection with the southbound East Interstate 19 frontage road at Old Tucson Highway in Rio Rico."

But north at the Ruby Road and I-19, Jungmeyer said, "what the community is going to see there is that it's going to put added pressure on an already congested interchange."

Jungmeyer and Valencia said major improvements are needed at the interchange to accommodate existing produce warehouses, the new building and future warehouses that could be drawn to the area by the development.

ADOT has been studying possible improvements there and at the Mariposa Road-I-19 intersection further south in Nogales, but last September agency employees told local officials and businesspeople that the up-to $200 million price tag for both far exceeds its $25-million-per-year budget for new construction. Jungmeyer said he was told the price tag for the Ruby Road exit could be around $10-$15 million.

However it happens, Jungmeyer said, "over time the income tax and sales tax generated by a company like (Delta) is obviously going to add to the state and the community and we've got to ... really redo that ... interchange."

Because such a project is probably years off, Valencia said the traffic situation is "going to get worse before it gets better."

A $7-million Love's Travel Stop including Subway and McDonald's restaurants, fuel pumps and spaces for approximately 90 trucks, had been slated to be built on property north of the new warehouse and just south of Ruby Road. ADOT initially permitted the project in 2008, but subsequently revoked the permit in late 2011 after finding that "several of the studied intersections are currently operating at an unacceptable level of service," according to an agency letter read by Mary Dahl, county community development director.

ADOT gave Love's the opportunity to modify designs to address their findings, "but at that point Mr. Love decided not to go forward," Dahl said.

Dahl said that because the gas station would have attracted both cars and commercial trucks, and been much closer to the high-traffic Ruby Road interchange, "it would have been a completely different dynamic than Mr. Panousopoulous' warehouse."

Water supply

In the past, local fire officials have also raised concerns about water access and pressure in the area around the new warehouse. Low water pressure reportedly slowed efforts to extinguish a fire at Soto's Pete Kitchen Outpost restaurant in April 2011, and two months later, firefighters lost valuable time trucking water to a fire at an abandoned home on Old Tucson Road.

However, both Nogales Suburban Fire Chief Carlos Parra and Rio Rico Fire inspector George Cluff, who signed off on the warehouse project, said improvements planned at the facility adequately address those concerns.

In his email, Panousopoulous wrote that the "water supply provided by Valle Verde Water Company is sufficient."

SIDEBAR:

Is it the biggest?

Daniel Menefee, chief county building official, wrote in an email that at "208,890 square feet (the new Delta Properties warehouse) appears to be the largest (warehouse) in Santa Cruz County to date and will be a refrigerated produce operation."

Dino Panousopoulous, who owns Delta Properties, said that the Nogales Border Patrol Station on West La Quinta Road and a neighboring warehouse are larger local facilities than his new structure. However, county assessor records put the warehouse just south of the station, also owned by Delta Properties, at an even 200,000 square feet.

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Feb 26, 2016

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SolarCity

3055 Clearview Way, San Mateo, CA 94402
T (888) SOL-CITY F (650) 560-6460 SOLARC

SolarLease

SUMMARY

Date: 9/19/2014

Customer Name and Address	Customer Name	Installation Location	Contractor License
[redacted]		[redacted]	**AZ ROC 243771,ROC 245450,ROC 277498**

EXHIBIT
UNSE-43
admitted

Estimated Solar Energy Production

First Year Annual Production:	14,270 kWh
Initial Term Total Production:	272,247 kWh

Payment Terms

Amount Due at Contract Signing:	$0
Amount Due when Installation Begins:	$0.00
Amount Due following Bldg. Inspection:	$0.00
Annual Increase:	2.90%
First Year Monthly SolarCity Bill:	$107.03
Lease Term	20 Years

SolarCity's Promises to You:

- SolarCity will insure, maintain, and repair the System (including the inverter) at no additional cost to you as specified in the agreement.
- SolarCity will provide 24/7 web-enabled monitoring at no additional cost to you, as specified in the agreement.
- SolarCity will provide a money-back production guarantee, as specified in the agreement.
- SolarCity will warranty your roof against leaks and restore your roof at the end of the agreement as specified in the agreement.
- The pricing in this Lease is valid for 30 days after 9/19/2014. If you don't sign this Lease and return it to us on or prior to 30 days after 9/19/2014, SolarCity reserves the right to reject this Lease unless you agree to our then current pricing.
- We are confident that we deliver excellent value and customer service. AS A RESULT, YOU ARE FREE TO CANCEL ANYTIME AT NO CHARGE PRIOR TO CONSTRUCTION ON YOUR HOME.

Your Prepayment and Transfer Choices During the Term:

- If you move, you may transfer this agreement to the purchaser of your Home, as specified in the agreement.
- If you move, you may prepay the remaining payments (if any) at a discount.

Your Choices at the End of the Initial Term:

- SolarCity will remove the System at no additional cost to you.
- You can upgrade to a new System with the latest solar technology under a new contract.
- You may renew your agreement for up to ten (10) years in two (2) five (5) year increments.
- Otherwise, the agreement will automatically renew for an additional one (1) year term at 10% less than the then-current average rate charged by your local utility.

SolarLease version 6.6.0, September 16th, 2014
282792
SAPC/SEFA Compliant
Document Generated on 9/19/2014

1. INTRODUCTION

This SolarLease® (this "Lease") is the agreement between you and SolarCity Corporation (together with its successors and assigns, "SolarCity" or "we"), covering the lease to you of the solar panel system (the "System") described below. The System will be installed by SolarCity at the address you listed above. This Lease will refer to this address as the "Property" or your "Home." This Lease is up to thirteen (13) pages long and has up to three (3) Exhibits depending on the state where you live. This Lease has disclosures required by the Federal Consumer Leasing Act and, where applicable, state law. SolarCity provides you with a Performance Guarantee and Limited Warranty (the "Limited Warranty"). The Limited Warranty is attached as **Exhibit 2**. SolarCity will also provide you with a System user manual entitled "Solar Operation and Maintenance Guide" (the "Guide"), that contains important operation, maintenance and service information. This is a legally binding agreement, so please read everything carefully including all of the exhibits. If you do not meet your contract obligations under this Lease, you may lose your rights to the System. If you have any questions regarding this Lease, please ask your SolarCity sales consultant.

2. LEASE TERM

SolarCity agrees to lease you the System for **20** years (240 full calendar months), plus, if the Interconnection Date is not on the first day of a calendar month, the number of days left in that partial calendar month, including the Interconnection Date. We refer to this period of time as the "Lease Term." The Lease Term begins on the Interconnection Date. The Interconnection Date is the date that the System is turned on and generating power. SolarCity will notify you by email when your System is ready to be turned on.

3. SYSTEM DESCRIPTION

Item
8.000 kW DC (STC) photovoltaic system
Photovoltaic Modules
Inverter(s)
Mounting system
Monitoring system
Electric meter number:
Extras:
Standard PowerGuide

4. LEASE PAYMENTS; AMOUNTS

A. Amounts Due at Lease Signing, Installation and Building Inspection:

Payments Due at Signing:
Amount Due at Lease Signing:
$0.00
Delivery/Installation Fee:
$0.00
Total Due at Lease Signing:
$0.00

Payments Due at Installation:
$0.00

Payments Due after Building Inspection:
$0.00

B. Monthly Payments:

Your first monthly payment is $107.03,
followed by 11 monthly payments of $107.03 each,
followed by 12 monthly payments of $110.13 each,
followed by 12 monthly payments of $113.32 each,
followed by 12 monthly payments of $116.61 each,
followed by 12 monthly payments of $119.99 each,
followed by 12 monthly payments of $123.47 each,
followed by 12 monthly payments of $127.05 each,
followed by 12 monthly payments of $130.73 each,
followed by 12 monthly payments of $134.52 each,
followed by 12 monthly payments of $138.42 each,
followed by 12 monthly payments of $142.43 each,
followed by 12 monthly payments of $146.56 each,
followed by 12 monthly payments of $150.81 each,
followed by 12 monthly payments of $155.18 each,
followed by 12 monthly payments of $159.68 each,
followed by 12 monthly payments of $164.31 each,
followed by 12 monthly payments of $169.07 each,
followed by 12 monthly payments of $173.97 each,
followed by 12 monthly payments of $179.02 each,
followed by 12 monthly payments of $184.21 each.

Your total lease payments, excluding tax, are **$34,158.12**. Your estimated average monthly tax payments are $0.00.

Your first Monthly Payment is due on the first day of the first full calendar month following the Interconnection Date. After your first Monthly Payment, future Monthly Payments (and any applicable taxes) are due on the first day of the calendar month.

C. Other Charges:	**D. Total of Payments (A+B+C) = $34,158.12**
If you make your Monthly Payments by allowing us to automatically debit your checking or savings account, then you will receive a discount of $7.50 on your Monthly Payments. The Monthly Payments listed above reflect this discount. If you do not allow the automatic debit, this discount will not be applied to your Monthly Payments and each Monthly Payment will be $7.50 greater.	This is the total amount you will have paid by the end of this Lease. It includes the Monthly Payments stated above <u>and</u> estimated taxes of $0.00.
E. Purchase Option At End of Lease Term:	**F. Other Important Terms:**
You do not have an option to purchase the System at the end of the Lease Term.	See Section 2 above for additional information on the Lease Term and also see below for additional information on termination, purchase options, renewal options, maintenance responsibilities, warranties, late and default charges and prohibition on assignment without SolarCity's consent. Payments due upon installation are due immediately prior to commencement of installation.

5. LEASE OBLIGATIONS

(a) System, Home and Property Maintenance

You agree to:

(i) only have the System repaired pursuant to the Limited Warranty and reasonably cooperate when repairs are being made;

(ii) keep trees, bushes and hedges trimmed so that the System receives as much sunlight as it did when SolarCity installed it;

(iii) keep the panels clean, pursuant to the Limited Warranty and the Guide;

(iv) not modify your Home in a way that shades the System;

(v) be responsible for any conditions at your Home that affect the installation (e.g. blocking access to the roof or removing a tree that is in the way, prior work you have done on your home that was not permitted);

(vi) not remove any markings or identification tags on the System;

(vii) permit SolarCity, after we give you reasonable notice, to inspect the System for proper operation as we reasonably determine necessary;

(viii) use the System primarily for personal, family or household purposes, but not to heat a swimming pool;

(ix) not do anything, permit or allow to exist any condition or circumstance that would cause the System not to operate as intended at the Property;

(x) notify SolarCity if you think the System is damaged or appears unsafe; if the System is stolen; and prior to changing your power supplier;

(xi) have anyone who has an ownership interest in your Home sign this Lease;

(xii) return any documents we send you for signature (like incentive claim forms) within seven (7) days of receiving them; and

(xiii) maintain and make available, at your cost, a functioning indoor internet connection with a router, one DHCP enabled Ethernet port with internet access and standard AC power outlet close enough and free of interference to enable an internet-connected gateway provided by SolarCity to communicate wirelessly with the system's inverter (typically this is 80 feet, but may depend on site conditions).See Section 2(d) of the Limited Warranty for details; and

(xiv) if your home is governed by a home owner's association or similar community organization, obtain all approvals and authorizations for the System required by that organization and advise us of any requirements of that organization that will otherwise impact the System, its installation or operation.

(b) System Construction, Repair, Insurance and SolarCity's obligations:

SolarCity agrees to:

(i) schedule the installation of the System at a mutually convenient date and time;

(ii) construct the System according to written plans you review;

(iii) provide you with a web-enabled meter to accurately measure the amount of power the System delivers to you;

(iv) notify you if the System design has to be materially changed so that you can review any such changes;

(v) clean up after ourselves during the construction of the System;

(vi) repair the System pursuant to the Limited Warranty and reasonably cooperate with you when scheduling repairs;

(vii) create a priority stream of operation and maintenance payments to provide enough cash flow in our financing transactions to pay for the Limited Warranty obligations and the repair and maintenance of the System in accordance with this Lease even if SolarCity ceases to operate; and

(viii) not put a lien on your Home or Property.

(c) Home Renovations or Repairs

If you want to make any repairs or improvements to the Property that could interfere with the System (such as repairing the roof where the System is located), you may only remove and replace the System pursuant to the Limited Warranty.

(d) Automatic Payment; Fees; Late Charges

In addition to the other amounts you agree to pay in this Lease, you agree to pay the following:

(i) Automatic Payment Discount: All prices include a $7.50 monthly discount for allowing us to automatically debit your checking or savings account for payments. You will not receive a $7.50 monthly discount if you do not allow the automatic debit;

(ii) Returned Check Fee: $25 (or such lower amount as required by law) for any check or withdrawal right that is returned or refused by your bank; and

(iii) Late payments: accrue interest at twelve percent (12%) annually or the maximum allowable by applicable law.

(e) Insurance

SolarCity shall insure the System against all damage or loss unless (i) that damage or loss is caused by your gross negligence; or (ii) you intentionally damage the System.

(f) Estimated Taxes

You agree to pay any applicable sales or use taxes on the Monthly Payments due under this Lease. If this Lease contains a purchase option at the end of the Lease Term, you agree to pay any applicable tax on the purchase price for the System. You also agree to pay as invoiced any applicable personal property taxes on the System that your local jurisdiction may levy. The total estimated amount you will pay for taxes over the Lease Term is **$0.00**.

(g) No Alterations

You agree that you will not make any modifications, improvements, revisions or additions to the System or take any other action that could void the Limited Warranty on the System without SolarCity's prior written consent. If you make any modifications, improvements, revisions or additions to the System, they will become part of the System and shall be SolarCity's property.

(h) Access to the System

(i) You grant to SolarCity and its employees, agents and contractors the right to reasonably access all of the Property as necessary for the purposes of (A) installing, constructing, operating, owning, repairing, removing and replacing the System or making any additions to the System or installing complementary technologies on or about the location of the System; (B) enforcing SolarCity's rights as to this Lease and the System; (C) installing, using and maintaining electric lines, inverters and meters, necessary to interconnect the System to your electric system at the Property and/or to the utility's electric distribution system; or (D) taking any other action reasonably necessary in connection with the construction, installation, operation, maintenance, removal or repair of the System. This access right shall continue for up to ninety (90) days after this Lease expires to provide SolarCity with time to remove the System at the end of the Lease Term. SolarCity shall provide you with reasonable notice of its need to access the Property whenever commercially reasonable.

(ii) During the time that SolarCity has access rights you shall ensure that its access rights are preserved and shall not interfere with or permit any third party to interfere with such rights or access. You agree that the System is not a fixture, but SolarCity has the right to file any UCC-1 financing statement or fixture filing that confirms its interest in the System.

(i) Indemnity

To the fullest extent permitted by law, you shall indemnify, defend, protect, save and hold harmless SolarCity, its employees, officers, directors, agents, successors and assigns from any and all third party claims, actions, costs, expenses (including reasonable attorneys' fees and expenses), damages, liabilities, penalties, losses, obligations, injuries, demands and liens of any kind or nature arising out of, connected with, relating to or resulting from your negligence or willful misconduct; provided, that nothing herein shall require you to indemnify SolarCity for its own negligence or willful misconduct. The provisions of this paragraph shall survive termination or expiration of this Lease.

(j) Monthly Payments

The Monthly Payments section (Section 4(B)) describes your monthly payment obligations under this Lease. YOU AGREE THAT THIS IS A NET LEASE AND THE OBLIGATION TO PAY ALL MONTHLY PAYMENTS AND ALL OTHER AMOUNTS DUE UNDER THIS LEASE SHALL BE ABSOLUTE

AND UNCONDITIONAL UNDER ALL CIRCUMSTANCES AND SHALL NOT BE SUBJECT TO ANY ABATEMENT, DEFENSE, COUNTERCLAIM, SETOFF, RECOUPMENT OR REDUCTION FOR ANY REASON WHATSOEVER, IT BEING THE EXPRESS INTENT OF THE PARTIES THAT ALL AMOUNTS PAYABLE BY YOU HEREUNDER SHALL BE AND CONTINUE TO BE PAYABLE IN ALL EVENTS INCLUDING BY YOUR HEIRS AND ESTATE AND, EXCEPT AS SET FORTH BELOW IN SECTIONS 6, 23 AND 24, YOU HEREBY WAIVE ALL RIGHTS YOU MAY HAVE TO REJECT OR CANCEL THIS LEASE, TO REVOKE ACCEPTANCE OF THE SYSTEM, OR TO GRANT A SECURITY INTEREST IN THE SYSTEM.

(k) You authorize SolarCity, or its designee, to obtain your credit report now and in the future, check your credit and employment history, answer questions others may ask regarding your credit and share your credit information with SolarCity's financing partners. You certify that all information you provide to us in connection with checking your credit will be true and understand that this information must be updated upon request if your financial condition changes.

6. CONDITIONS PRIOR TO INSTALLATION OF THE SYSTEM

(a) SolarCity's Obligation to Install and Lease

SolarCity's obligations to install and lease the System are conditioned on the following items having been completed to its reasonable satisfaction:

(i) completion of (A) the engineering site audit (a thorough physical inspection of the Property, including, if applicable, geotechnical work), (B) the final System design, and (C) real estate due diligence to confirm the suitability of the Property for the construction, installation and operation of the System;

(ii) approval of this Lease by SolarCity's financing partner(s);

(iii) your meeting the applicable credit score;

(iv) confirmation of rebate, tax credit and renewable energy credit payment availability in the amount used to calculate the Monthly Payment amounts set forth in this Lease;

(v) confirmation that SolarCity will obtain all applicable benefits referred to in Section 9;

(vi) receipt of all necessary zoning, land use and building permits; and

(vii) completion of any renovations, improvements or changes reasonably required at your Home or on the Property (e.g. removal of a tree or roof repairs necessary to enable SolarCity to safely install the System); and

(viii) if your home is governed by a home owner's association or similar community organization, your receipt of all approvals and authorizations for the System required by that organization and advising us of any requirements of that organization that will otherwise impact the System, its installation or operation.

SolarCity may terminate this Lease without liability if, in its reasonable judgment, any of the above listed conditions (i) through (vi) will not be satisfied for reasons beyond its reasonable control. Once SolarCity starts installation, however, it may not terminate this Lease for the failure to satisfy conditions (i) through (vi) above.

(b) Amendments, Your Right to Terminate for Material Changes.

Both parties will have the right to terminate this Lease, without penalty or fee, if SolarCity determines after the engineering site audit of your Home that it has misestimated by more than ten percent (10%) any of (i) the System size, (ii) the System's total cost or (iii) the System's annual production. Such termination right will expire at the **earlier** of (A) one (1) week prior to the scheduled System installation date and (B) one (1) month after we inform you in writing of the revised size, cost or production estimate. If neither party exercises their right to terminate this Lease following such a 10% change, then any changes to the System will be documented in an amendment to this Lease. You authorize SolarCity to make corrections to the utility paperwork to conform to this Lease or any amendments to this Lease we both sign.

7. WARRANTY

YOU UNDERSTAND THAT THE SYSTEM IS WARRANTED SOLELY UNDER THE LIMITED WARRANTY ATTACHED AS **EXHIBIT 2**, AND THAT THERE ARE NO OTHER REPRESENTATIONS OR WARRANTIES, EXPRESS OR IMPLIED, AS TO THE MERCHANTABILITY, FITNESS FOR ANY PURPOSE, CONDITION, DESIGN, CAPACITY, SUITABILITY OR PERFORMANCE OF THE SYSTEM OR ITS INSTALLATION.

8. TRANSFER

SolarCity works with banks, large companies and other significant financing partners to finance your System. As a result, SolarCity will assign this Lease to one of its financing partners. SolarCity may assign, sell or transfer the System and this Lease, or any part of this Lease or the exhibits, without your consent. Assignment, sale or transfer generally means that SolarCity would transfer certain of its rights and certain of its obligations under this Lease to another party. This assignment does not change SolarCity's obligation to maintain and repair your System as set forth in the Limited Warranty.

9. OWNERSHIP OF THE SYSTEM; TAX CREDITS AND REBATES

You agree that the System is SolarCity's personal property under the Uniform Commercial Code. You understand and agree that this is a lease and not a sale agreement. SolarCity owns the System for all purposes, including any data generated from the System. You shall at all times keep the System free and clear of all liens, claims, levies and legal processes not created by SolarCity, and shall at your expense protect and defend SolarCity against the same.

YOU UNDERSTAND AND AGREE THAT ANY AND ALL TAX CREDITS, INCENTIVES, RENEWABLE ENERGY CREDITS, GREEN TAGS, CARBON OFFSET CREDITS, UTILITY REBATES OR ANY OTHER NON-POWER ATTRIBUTES OF THE SYSTEM ARE THE PROPERTY OF AND FOR THE BENEFIT OF SOLARCITY, USABLE AT ITS SOLE DISCRETION. SOLARCITY SHALL HAVE THE EXCLUSIVE RIGHT TO ENJOY AND USE ALL SUCH BENEFITS, WHETHER SUCH BENEFITS EXIST NOW OR IN THE FUTURE. YOU AGREE TO REFRAIN FROM ENTERING INTO ANY AGREEMENT WITH YOUR UTILITY THAT WOULD ENTITLE YOUR UTILITY TO CLAIM ANY SUCH BENEFITS. YOU AGREE TO REASONABLY COOPERATE WITH SOLARCITY SO THAT IT MAY CLAIM ANY TAX CREDITS, RENEWABLE ENERGY CREDITS, REBATES, CARBON OFFSET CREDITS OR ANY OTHER BENEFITS FROM THE SYSTEM. THIS MAY INCLUDE, TO THE EXTENT ALLOWABLE BY LAW, ENTERING INTO NET METERING AGREEMENTS, INTERCONNECTION AGREEMENTS, AND FILING RENEWABLE ENERGY/CARBON OFFSET CREDIT REGISTRATIONS AND/OR APPLICATIONS FOR REBATES FROM THE FEDERAL, STATE OR LOCAL GOVERNMENT OR A LOCAL UTILITY AND GIVING THESE TAX CREDITS, RENEWABLE ENERGY/CARBON CREDITS, REBATES OR OTHER BENEFITS TO SOLARCITY.

10. PURCHASING THE SYSTEM PRIOR TO THE END OF THE LEASE TERM

You do not have an option to purchase the System at the end of the Lease Term.

11. RENEWAL

If you are in compliance with your Lease, you have the option to renew your Lease for up to ten (10) years in two (2) five (5) year renewal periods. We will send you renewal forms three (3) months prior to the expiration of the Lease Term, which forms shall set forth the new Monthly Payments due under the renewed Lease, based on our assessment of the then current fair market value of the System. If you want to renew, complete the renewal forms and return them to us at least one (1) month prior to the expiration of the Lease Term. In the event that you respond that you do not agree to the new Monthly Payments, the Lease shall expire by its terms on the termination date. If you don't send us anything in writing after we send you the renewal forms, then this Lease shall renew for an additional one (1) year term at ten percent (10%) less than the then-current average rate charged by your local utility and shall continue to renew for one (1) year terms at that same rate until (i) you give us notice at least thirty (30) days prior to a renewal term that you do not wish to renew; or (ii) we send you a notice terminating the Lease.

12. SELLING YOUR HOME

(a) If you sell your Home you can:

(i) **Transfer this Lease and the Monthly Payments.**

If the person buying your Home meets SolarCity's credit requirements, then where permitted by the local utility, the person buying your Home can sign a transfer agreement assuming all of your rights and obligations under this Lease.

(ii) **Move the System to Your New Home.**

If you are moving to a new home in the same utility district, then where permitted by the local utility, the System can be moved to your new home pursuant to the Limited Warranty. You will need to pay all costs associated with relocating the System, execute and provide the same access and ownership rights as provided for in this Lease and provide any third party consents or releases required by SolarCity in connection with the substitute premises.

(iii) Prepay this Lease and Transfer only the Use of the System.

At any time during the Lease Term, if the person buying your home does not meet SolarCity's credit requirements, but still wants the System, then you can (A) prepay the payments remaining on the Lease (See Section 16(i)(i) and (ii)), (B) add the cost of the Lease to the price of your home; and (C) have the person buying your Home sign a transfer agreement to assume your rights and non-Monthly Payment obligations under this Lease. The System stays at your Home, the person buying your Home does not make any Monthly Payments and has only to comply with the non-Monthly Payment portions of this Lease.

(b) You agree to give SolarCity at least fifteen (15) days but not more than three (3) months' prior written notice if you want someone to assume your Lease obligations. In connection with this assumption, you, your approved buyer and SolarCity shall execute a written transfer of this Lease. Unless we have released you from your obligations in writing, you are still responsible for performing under this Lease. If your buyer defaults on this Lease and we have not yet signed the transfer agreement, you will be responsible for their default. We will release you from your obligations under this Lease in writing once we have a signed transfer agreement with the person buying your Home (provided such person has been approved as a transferee by SolarCity in writing).

(c) If you sell your Home and can't comply with any of the options in subsection (a) above, you will be in default under this Lease. Section 12(a) includes a Home sale by your estate or heirs.

(d) EXCEPT AS SET FORTH IN THIS SECTION, YOU WILL NOT SUBLEASE, ASSIGN, SELL, PLEDGE OR IN ANY OTHER WAY TRANSFER YOUR INTEREST IN THE SYSTEM OR THIS LEASE WITHOUT OUR PRIOR WRITTEN

CONSENT, WHICH SHALL NOT BE UNREASONABLY WITHHELD.

13. LOSS OR DAMAGE

(a) Unless you are grossly negligent or you intentionally damage the System, SolarCity will bear all of the risk of loss, damage, theft, destruction or similar occurrence to any or all of the System. Except as expressly provided in this Lease, no loss, damage, theft or destruction will excuse you from your obligations under this Lease, including Monthly Payments.

(b) If there is loss, damage, theft, destruction or a similar occurrence affecting the System, and you are not in default of this Lease, you shall continue to timely make all Monthly Payments and pay all other amounts due under the Lease and, cooperate with SolarCity, at SolarCity's sole cost and expense, to have the System repaired pursuant to the Limited Warranty.

14. LIMITATION OF LIABILITY

(a) No Consequential Damages

SOLARCITY'S LIABILITY TO YOU UNDER THIS LEASE SHALL BE LIMITED TO DIRECT, ACTUAL DAMAGES ONLY. YOU AGREE THAT IN NO EVENT SHALL EITHER PARTY BE LIABLE TO THE OTHER FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY, SPECIAL OR INDIRECT DAMAGES.

(b) Actual Damages

Except for claims under Section 5(i), neither party's liability to the other will exceed an amount equal to the maximum amount that could be payable by you under Section 16(i). Damages to your Home, belongings or property resulting from the installation or operation of the System are covered in Section 6(c) of the Limited Warranty.

15. DEFAULT

You will be in default under this Lease if any one of the following occurs:

(a) you fail to make any payment when it is due and such failure continues for a period of ten (10) days;

(b) you fail to perform any material obligation that you have undertaken in this Lease (which includes doing something you have agreed not to do, like alter the System) and such failure continues for a period of fourteen (14) days after written notice;

(c) you or your guarantor have provided any false or misleading financial or other information to obtain this Lease;

(d) you assign, transfer, encumber, sublet or sell this Lease or any part of the System without SolarCity's prior written consent; or

(e) you or any guarantor makes an assignment for the benefit of creditors, admits in writing its insolvency, files or there is filed against you or it a voluntary petition in bankruptcy, is adjudicated bankrupt or insolvent or undertakes or experiences any substantially similar activity.

16. REMEDIES IN CASE OF DEFAULT

If this Lease is in default, we may take any one or more of the following actions. If the law requires us to do so, we will give you notice and wait any period of time required before taking any of these actions. We may:

(a) terminate this Lease and your rights to possess and use the System;

(b) suspend our performance under this Lease;

(c) take any reasonable action to correct your default or to prevent our loss; any amount we pay will be added to the amount you owe us and will be immediately due;

(d) require you, at your expense, to return the System or make it available to us in a reasonable manner;

(e) proceed, by appropriate court action, to enforce performance of this Lease and to recover damages for your breach;

(f) disconnect, turn off or take back the System by legal process or self-help, but we may not disturb the peace or violate the law;

(g) report such non-operational status of the System to your utility, informing them that you are no longer net metering;

(h) charge you a reasonable reconnection fee for reconnecting the System to your utility or turning your System back on after we disconnect or turn off the System due to your default;

(i) recover from you (i) all accrued but unpaid Monthly Payments, taxes, late charges, penalties, interest and all or any other sums then accrued or due and owing, plus (ii) the unpaid balance of the aggregate rent, each payment discounted to present value at 5% per annum, plus (iii) reasonable compensation, on a net after tax basis assuming a tax rate of 35%, for the loss or recapture of (A) the investment tax credit equal to thirty percent (30%) of the System cost, including installation; and (B) accelerated depreciation over five (5) years equal to eighty five percent (85%) of the System cost, including installation, and for the loss of any anticipated benefits pursuant to Section 9 of this Lease (SolarCity shall furnish you with a detailed calculation of such compensation if such a claim is made); or

(j) use any other remedy available to us in this Lease or by law.

You agree to repay us for any reasonable amounts we pay to correct or cover your default. You also agree to reimburse us for any costs and expenses we incur relating to the System's return resulting from early termination. By choosing any one or more of these remedies, SolarCity does not give up its right to use another remedy. By deciding not to use any remedy should this Lease be in default, SolarCity does not give up our right to use that remedy in case of a subsequent default.

We may submit to credit reporting agencies (credit bureaus) negative credit reports that would be reflected on your credit record if you do not pay any amounts due under this Lease as required.

17. SYSTEM REMOVAL; RETURN

At the end of the Term or the termination of this Lease, if you have not renewed this Lease or exercised your purchase option (if any) and you have not defaulted, then within ninety (90) days you agree to call SolarCity at the telephone number listed in Section 7 of Exhibit 2 to schedule a convenient time for SolarCity to remove the System from your Home at no cost to you.

18. APPLICABLE LAW; ARBITRATION

PLEASE READ THIS SECTION CAREFULLY. ARBITRATION REPLACES THE RIGHT TO GO TO COURT, INCLUDING THE RIGHT TO A JURY AND THE RIGHT TO PARTICIPATE IN A CLASS ACTION OR SIMILAR PROCEEDING. IN ARBITRATION, A DISPUTE IS RESOLVED BY AN ARBITRATOR INSTEAD OF A JUDGE OR JURY.

The laws of the state where your Home is located shall govern this Lease without giving effect to conflict of laws principles. We agree that any dispute, claim or disagreement between us (a "Dispute") shall be resolved exclusively by arbitration.

The arbitration, including the selecting of the arbitrator, will be administered by JAMS, under its Streamlined Arbitration Rules (the "Rules") by a single neutral arbitrator agreed on by the parties within thirty (30) days of the commencement of the arbitration. The arbitration will be governed by the Federal Arbitration Act (Title 9 of the U.S. Code). Either party may initiate the arbitration process by filing the necessary forms with JAMS. To learn more about arbitration, you can call any JAMS office or review the materials at www.jamsadr.com. The arbitration shall be held in the location that is most convenient to your Home. If a JAMS office does not exist within fifty (50) miles of your Home , then we will use another accredited arbitration provider with offices close to your Home.

If you initiate the arbitration, you will be required to pay the first $125 of any filing fee. We will pay any filing fees in excess of $125 and we will pay all of the arbitration fees and costs. If we initiate the arbitration, we will pay all of the filing fees and all of the arbitration fees and costs. We will each bear all of our own attorney's fees and costs except that you are entitled to recover your attorney's fees and costs if you prevail in the arbitration and the award you receive from the arbitrator is higher than SolarCity's last written settlement offer. When determining whether your award is higher than SolarCity's last written settlement offer your attorney's fees and costs will not be included.

Only Disputes involving you and SolarCity may be addressed in the arbitration. Disputes must be brought in the name of an individual person or entity and must proceed on an individual (non-class, non-representative) basis. The arbitrator will not award relief for or against anyone who is not a party. If either of us arbitrates a Dispute, neither of us, nor any other person, may pursue the Dispute in arbitration as a class action, class arbitration, private attorney general action or other representative action, nor may any such Dispute be pursued on your or our behalf in any litigation in any court. Claims regarding any Dispute and remedies sought as part of a class action, class arbitration, private attorney general or other representative action are subject to arbitration on an individual (non-class, non-representative) basis, and the arbitrator may award relief only on an individual (non-class, non-representative) basis. This means that the arbitration may not address disputes involving other persons with disputes similar to the Disputes between you and SolarCity.

The arbitrator shall have the authority to award any legal or equitable remedy or relief that a court could order or grant under this agreement. The arbitrator, however, is not authorized to change or alter the terms of this agreement or to make any award that would extend to any transaction other than yours. All statutes of limitations that are applicable to any dispute shall apply to any arbitration between us. The Arbitrator will issue a decision or award in writing, briefly stating the essential findings of fact and conclusions of law.

BECAUSE YOU AND WE HAVE AGREED TO ARBITRATE ALL DISPUTES, NEITHER OF US WILL HAVE THE RIGHT TO LITIGATE THAT DISPUTE IN COURT, OR TO HAVE A JURY TRIAL ON THAT DISPUTE, OR ENGAGE IN DISCOVERY EXCEPT AS PROVIDED FOR IN THE RULES. FURTHER, YOU WILL NOT HAVE THE RIGHT TO PARTICIPATE AS A REPRESENTATIVE OR MEMBER OF ANY CLASS PERTAINING TO ANY DISPUTE. THE ARBITRATOR'S DECISION WILL BE FINAL AND BINDING ON THE PARTIES AND MAY BE ENTERED AND ENFORCED IN ANY COURT HAVING JURISDICTION, EXCEPT TO THE EXTENT IT IS SUBJECT TO REVIEW IN ACCORDANCE WITH APPLICABLE LAW GOVERNING ARBITRATION AWARDS. OTHER RIGHTS THAT YOU OR WE WOULD HAVE IN COURT MAY ALSO NOT BE AVAILABLE IN ARBITRATION.

19. WAIVER

Any delay or failure of a party to enforce any of the provisions of this Lease, including but not limited to any remedies listed in this Lease, or to require performance by the other party of any of the provisions of this Lease, shall not be construed to (i) be a waiver of such provisions or a party's right to enforce that provision; or (ii) affect the validity of this Lease.

20. NOTICES

All notices under this Lease shall be in writing and shall be by personal delivery, facsimile transmission, electronic mail, overnight courier, or certified, or registered mail, return receipt requested, and deemed received upon personal delivery, acknowledgment of receipt of electronic transmission, the promised delivery date after deposit with overnight courier, or five (5) days after deposit in the mail. Notices shall be sent to the person identified in this Lease at the addresses set forth in this Lease or such other address as either party may specify in writing. Each party shall deem a document faxed or sent via PDF as an original document.

21. ENTIRE AGREEMENT; CHANGES

This Lease contains the parties' entire agreement regarding the lease of the System. There are no other agreements regarding this Lease, either written or oral. Any change to this Lease must be in writing and signed by both parties. If any portion of this Lease is determined to be unenforceable, the remaining provisions shall be enforced in accordance with their terms or shall be interpreted or re-written so as to make them enforceable.

REST OF PAGE INTENTIONALLY LEFT BLANK

22. PUBLICITY

SolarCity will not publicly use or display any images of the System unless you initial the space below. If you initial the space below, you give SolarCity permission to take pictures of the System as installed on your Home to show to other customers or display on our website.

Homeowner's Initials
}}

23. NOTICE OF RIGHT TO CANCEL

YOU MAY CANCEL THIS LEASE AT ANY TIME PRIOR TO MIDNIGHT OF THE THIRD BUSINESS DAY AFTER THE DATE YOU SIGN THIS LEASE. SEE EXHIBIT 1, THE ATTACHED NOTICE OF CANCELLATION FORM, FOR AN EXPLANATION OF THIS RIGHT.

24. ADDITIONAL RIGHTS TO CANCEL

IN ADDITION TO ANY RIGHTS YOU MAY HAVE TO CANCEL THIS LEASE UNDER SECTIONS 6 AND 23, YOU MAY ALSO CANCEL THIS LEASE AT NO COST AT ANY TIME PRIOR TO COMMENCEMENT OF CONSTRUCTION ON YOUR HOME.

25. Pricing

The pricing in this Lease is valid for 30 days after 9/19/2014. If you don't sign this Lease and return it to us on or prior to 30 days after 9/19/2014, SolarCity reserves the right to reject this Lease unless you agree to our then current pricing.

I have read this Lease and the Exhibits in their entirety and I acknowledge that I have received a complete copy of this Lease.

Customer's Name: [redacted]

Signature: DocuSigned by: [redacted] CCF6CE77F0884D7...

Date: 9/19/2014

Customer's Name:

Signature:

Date:

SolarCity

SolarLease

SOLARCITY APPROVED

Signature:

LYNDON RIVE, CEO

SolarLease

SolarCity

Date: 9/19/2014

EXHIBIT 1 (SOLARCITY COPY)
NOTICE OF CANCELLATION
STATUTORILY-REQUIRED LANGUAGE
Notice of Cancellation

Date of Transaction: The date you signed the Lease.

You may CANCEL this transaction, without any penalty or obligation, within THREE BUSINESS DAYS from the above date. If you cancel, any property traded in, any payments made by you under the contract or sale and any negotiable instrument executed by you will be returned within TEN DAYS following receipt by the seller (SolarCity Corporation) of your cancellation notice, and any security interest arising out of the transaction will be canceled. If you cancel, you must make available to the seller (SolarCity Corporation) at your residence, in substantially as good condition as when received, any goods delivered to you under this contract or sale, or you may, if you wish, comply with the instructions of the seller (SolarCity Corporation) regarding the return shipment of the goods at the seller's (SolarCity Corporation's) expense and risk. If you do make the goods available to the seller (SolarCity Corporation) and the seller (SolarCity Corporation) does not pick them up within 20 days of the date of your notice of cancellation, you may retain or dispose of the goods without any further obligation. If you fail to make the goods available to the seller (SolarCity Corporation), or if you agree to return the goods to the seller (SolarCity Corporation) and fail to do so, then you remain liable for performance of all obligations under the contract.

To cancel this transaction, mail or deliver a signed and dated copy of this cancellation notice, or any other written notice, or send a telegram to SolarCity Corporation, 3055 Clearview Way, San Mateo, CA 94402 NOT LATER THAN MIDNIGHT of the date that is THREE BUSINESS DAYS from the date you signed the Lease.

I, [redacted], hereby cancel this transaction on ______________________ [Date].

Customer's Signature:

____

Customer's Signature:

____

EXHIBIT 1 (CUSTOMER COPY)
NOTICE OF CANCELLATION
STATUTORILY-REQUIRED LANGUAGE
Notice of Cancellation

Date of Transaction: The date you signed the Lease.

You may CANCEL this transaction, without any penalty or obligation, within THREE BUSINESS DAYS from the above date. If you cancel, any property traded in, any payments made by you under the contract or sale and any negotiable instrument executed by you will be returned within TEN DAYS following receipt by the seller (SolarCity Corporation) of your cancellation notice, and any security interest arising out of the transaction will be canceled. If you cancel, you must make available to the seller (SolarCity Corporation) at your residence, in substantially as good condition as when received, any goods delivered to you under this contract or sale, or you may, if you wish, comply with the instructions of the seller (SolarCity Corporation) regarding the return shipment of the goods at the seller's (SolarCity Corporation's) expense and risk. If you do make the goods available to the seller (SolarCity Corporation) and the seller (SolarCity Corporation) does not pick them up within 20 days of the date of your notice of cancellation, you may retain or dispose of the goods without any further obligation. If you fail to make the goods available to the seller (SolarCity Corporation), or if you agree to return the goods to the seller (SolarCity Corporation) and fail to do so, then you remain liable for performance of all obligations under the contract.

To cancel this transaction, mail or deliver a signed and dated copy of this cancellation notice, or any other written notice, or send a telegram to SolarCity Corporation, 3055 Clearview Way, San Mateo, CA 94402 NOT LATER THAN MIDNIGHT of the date that is THREE BUSINESS DAYS from the date you signed the Lease.

I, [redacted], hereby cancel this transaction on ______________________ [Date].

Customer's Signature:

____

Customer's Signature:

____

Exhibit 2

PERFORMANCE GUARANTEE AND LIMITED WARRANTY

1. INTRODUCTION

This Performance Guarantee and Limited Warranty (this "Limited Warranty") is SolarCity's agreement to provide you warranties on the System you leased. The System will be professionally installed by SolarCity at the address you listed in the Lease. We will refer to the installation location as your "Property" or your "Home." This Limited Warranty begins when we start installing the System at your Home. We look forward to helping you produce clean, renewable solar power at your Home.

2. LIMITED WARRANTIES

(a) Limited Warranties

SolarCity warrants the System as follows:

(i) System Warranty

During the entire Lease Term, under normal use and service conditions, the System will be free from defects in workmanship or defects in, or a breakdown of, materials or components (the "System Warranty");

(ii) Roof Warranty

When we penetrate your roof during a System installation we will warrant roof damage we cause due to our roof penetrations. This roof warranty will run the longer of (A) one (1) year following the completion of the System installation; and (B) the length of any existing installation warranty or new home builder performance standard for your roof (the "Roof Warranty Period"); and

(iii) Repair Promise

During the entire Lease Term, SolarCity will honor the System Warranty and will repair or replace any defective part, material or component or correct any defective workmanship, at no cost or expense to you (including all labor costs), when you submit a valid claim to us under this Limited Warranty (the "Repair Promise"). If we damage your Home, your belongings or your Property we will repair the damage we cause or pay you for the damage we cause as described in Section 6. SolarCity may use new or reconditioned parts when making repairs or replacements. SolarCity may also, at no additional cost to you, upgrade or add to any part of the System to ensure that it performs according to the guarantees set forth in this Limited Warranty. Cosmetic repairs that do not involve safety or performance shall be made at SolarCity's discretion.

(b) Warranty Length

(i) The warranties in Sections 2(a)(i) and (a)(iii) above will start when we begin installing the System at your Home and continue through the entire Lease Term. Thus, for as long as you lease the System from SolarCity, you will have a System Warranty and our Repair Promise.

(ii) The Roof Warranty Period may be shorter than the System Warranty, as described in Section 2(a)(ii) above.

(iii) If you have assumed an existing Lease, then this Limited Warranty will cover you for the remaining balance of the existing Lease Term.

(c) Performance Warranties and Guarantee

(i) Power Production Guarantee

SolarCity guarantees that during the Lease Term the System will generate kilowatt-hours (kWh) as set forth in the table below and calculated as follows. To calculate the guaranteed amount of kWh for an applicable two-year period ("Guaranteed kWh") we will take the applicable year's Total kWh in the chart below minus the Total kWh from two years prior, also as indicated in the chart below:

YEAR	TOTAL KWH	GUARANTEED PRICE/KWH
2	27,046	$0.0930
4	53,822	$0.0995
6	80,331	$0.1064
8	106,575	$0.1138
10	132,558	$0.1217
12	158,281	$0.1302
14	183,748	$0.1393
16	208,961	$0.1489
18	233,922	$0.1593
20	258,635	$0.1704

A. If at the end of each successive twenty four (24) month anniversary of your first monthly payment the cumulative Actual kWh (defined below) generated by the System is less than the Guaranteed kWh, **then we will send you a refund check** equal to the difference between the cumulative Actual kWh and the Guaranteed kWh multiplied by the Guaranteed Energy Price per kWh (defined below). Your cumulative Actual kWh is dependent on a shading percentage of 0 % on your Home. If this shading percentage increases, your Guaranteed Actual kWh will be reduced proportionately.

For example, if the first twenty four (24) month period commences on October 1, 2013 and ends on September 30, 2015, and the energy the System was supposed to generate is less than the energy the system was guaranteed to generate during such twenty four (24) month period, we will pay you the difference in the Actual kWh and the Guaranteed kWh multiplied by the Guaranteed Energy price per kWh within thirty (30) days after we receive your request. See the table below for a real world example.

Example Guaranteed kWh	**Example Actual kWh**	**Example Guaranteed $/kWh Energy Price**	**Example Payment to You**
10,000	9,500	$0.10	$50.00

B. If at the end of each successive twenty four (24) month anniversary of your first monthly payment the Actual kWh is ***greater*** than the Guaranteed kWh during any twenty four (24) month period, this surplus will be carried over and will be used to offset any deficits that may occur in the future. If over the course of the Term your System produces more energy than the Guaranteed Output then this additional energy is yours at no additional cost.

"**Actual kWh**" means the AC electricity produced by your System in kilowatt-hours measured and recorded by SolarCity during each successive twenty four (24) month anniversary of your first monthly payment. To measure the Actual kWh we will use the PowerGuide Solar Monitoring Service or to the extent such services are not available, we will estimate the Actual kWh by reasonable means.

"**Guaranteed Energy Price per kWh**" is set out in the table immediately after the first paragraph in Section 2(c)(i) above.

(ii) PowerGuide™ Solar Monitoring

During the Lease Term, we will provide you at no additional cost our PowerGuide Solar Monitoring Service ("PowerGuide"). PowerGuide is a proprietary monitoring system designed and installed by SolarCity that captures and displays historical energy generation data over an Internet connection and consists of hardware located on site and software hosted by SolarCity. If your System is not operating within normal ranges, PowerGuide will alert us and we will remedy any material issues promptly.

(d) Maintenance and Operation

(i) General

When the System is installed SolarCity will provide you with a copy of its Solar Operation and Maintenance Guide. This Guide provides you with System operation and maintenance instructions, answers to frequently asked questions, troubleshooting tips and service information.

(ii) PowerGuide

PowerGuide requires a high speed Internet line to operate. Therefore, during the Lease Term, you agree to maintain the communication link between PowerGuide and the System and between PowerGuide and the Internet. You agree to maintain and make available, at your cost, a functioning indoor internet connection with a router, one DHCP enabled Ethernet port with internet access and standard AC power outlet close enough and free of interference to enable an internet-connected gateway provided by SolarCity to communicate wirelessly with the system's inverter (typically this is 80 feet, but may depend on site conditions). This communication link must be a 10/100 Mbps Ethernet connection that supports common Internet protocols (TCP/IP and DHCP). If you do not have and maintain a working high speed Internet line then (A) we will not be able to monitor the System and provide you with the Power Production Guarantee or provide PowerGuide; and (B) you will be required to provide SolarCity with annual production information from your inverter.

(e) Making a Claim; Transferring this Warranty

(i) Claims Process

You can make a claim by:

A. emailing us at the email address in Section 7 below;

B. writing us a letter and sending it overnight mail with a well-known service; or

C. sending us a fax at the number in Section 7 below.

(ii) Transferable Limited Warranty

SolarCity will accept and honor any valid and properly submitted Warranty claim made during any Lease Term by any person who either purchases the System from you or to whom you properly transfer the Lease.

(f) Exclusions and Disclaimer

The limited warranties and guarantee provided in this Limited Warranty do not apply to any lost power production or any repair, replacement or correction required due to the following:

(i) someone other than SolarCity or its approved service providers installed, removed, re-installed or repaired the System;

(ii) destruction or damage to the System or its ability to safely produce power not caused by SolarCity or its approved service providers while servicing the System (e.g. if a tree falls on the System we will replace the System per the Lease, but we will not repay you for power it did not produce);

(iii) your failure to perform, or breach of, your obligations under the Lease (e.g. you modify or alter the System);

(iv) your breach of this Limited Warranty, including your being unavailable to provide access or assistance to us in diagnosing or repairing a problem, or your failing to maintain the System as stated in the Solar Operation and Maintenance Guide;

(v) any Force Majeure Event (as defined below);

(vi) shading from foliage that is new growth or is not kept trimmed to its appearance on the date the System was installed;

(vii) any system failure or lost production not caused by a System defect (e.g. the System is not producing power because it has been removed to make roof repairs or you have required us to locate the inverter in a non-shaded area); and

(viii) theft of the System (e.g. if the System is stolen we will replace the System per the Lease, but we will not repay you for the power it did not produce).

This Limited Warranty gives you specific rights, and you may also have other rights which vary from state to state. This Limited Warranty does not warrant any specific electrical performance of the System, other than that described above.

Snow or ice may accumulate on rooftops and on solar panels during snow storms. Accumulated snow or ice may slide or fall, resulting in property damage or bodily harm. If and when conditions safely allow you to remove accumulated snow or ice, you should do so to reduce the likelihood of excess snow sliding or falling.

THE LIMITED WARRANTIES DESCRIBED IN SECTIONS 2(a) and (c) ABOVE ARE THE ONLY EXPRESS WARRANTIES MADE BY SOLARCITY WITH RESPECT TO THE SYSTEM. SOLARCITY HEREBY DISCLAIMS, AND ANY BENEFICIARY OF THIS LIMITED WARRANTY HEREBY WAIVES, ANY WARRANTY WITH RESPECT TO ANY COST SAVINGS FROM USING THE SYSTEM. SOME STATES DO NOT ALLOW SUCH LIMITATIONS, SO THE ABOVE LIMITATIONS MAY NOT APPLY TO YOU.

3. SOLARCITY'S STANDARDS

For the purpose of this Limited Warranty the standards for our performance will be (i) normal professional standards of performance within the solar photovoltaic power generation industry in the relevant market; and (ii) Prudent Electrical Practices. "Prudent Electrical Practices" means those practices, as changed from time to time, that are engaged in or approved by a significant portion of the solar power electrical generation industry operating in the United States to operate electric equipment lawfully and with reasonable safety, dependability, efficiency and economy.

4. SYSTEM REPAIR, RELOCATION OR REMOVAL

(a) **Repair**. You agree that if (i) the System needs any repairs that are not the responsibility of SolarCity under this Limited Warranty, (ii) the system needs to be removed and reinstalled to facilitate remodeling of your Home or (iii) the system is being relocated to another home you own pursuant to the Lease, you will have SolarCity, or another similarly qualified service provider, at your expense, perform such repairs, removal and reinstallation, or relocation on a time and materials basis.

(b) **Removal/Moving**. SolarCity will remove and replace the System from your roof while roof repairs are being made for a payment of $499. You will need to provide storage space for the System during such time. Where permitted under the Lease, SolarCity will work with you to conduct an audit of your existing Home and new home to determine if a move is commercially feasible. This audit will cost $499. If SolarCity determines that a move is commercially feasible, it will then move the System for an additional payment of $499.

(c) **Return**. If at the end of the Term you want to return the System to SolarCity under Section 17 of the Lease then SolarCity will remove the System at no cost to you. SolarCity will remove the posts, waterproof the post area and return the roof as close as is reasonably possible to its original condition before the System was installed (e.g. ordinary wear and tear and color variances due to manufacturing changes are excepted). SolarCity will warrant the waterproofing for one (1) year after it removes the System. You agree to reasonably cooperate with SolarCity in removing the System including providing necessary space, access and storage, and we will reasonably cooperate with you to schedule removal in a time and manner that minimizes inconvenience to you.

5. FORCE MAJEURE

If SolarCity is unable to perform all or some of its obligations under this Limited Warranty because of a Force Majeure Event, SolarCity will be excused from whatever performance is affected by the Force Majeure Event, provided that:

(a) SolarCity, as soon as is reasonably practical, gives you notice describing the Force Majeure Event;

(b) SolarCity's suspension of its obligations is of no greater scope and of no longer duration than is required by the Force Majeure Event (i.e. when a Force Majeure Event is over, we will make repairs); and

(c) No SolarCity obligation that arose before the Force Majeure Event that could and should have been fully performed before such Force Majeure Event is excused as a result of such Force Majeure Event.

"Force Majeure Event" means any event, condition or circumstance beyond the control of and not caused by SolarCity's fault or negligence. It shall include, without limitation, failure or interruption of the production, delivery or acceptance of power due to: an act of god; war (declared or undeclared); sabotage; riot; insurrection; civil unrest or disturbance; military or guerilla action; terrorism; economic sanction or embargo; civil strike, work stoppage, slow-down, or lock-out; explosion; fire; earthquake; abnormal weather condition or actions of the elements; hurricane; flood; lightning; wind; drought; the binding order of any governmental authority (provided that such order has been resisted in good faith by all reasonable legal means); the failure to act on the part of any governmental authority (provided that such action has been timely requested and diligently pursued); unavailability of power from the utility grid, equipment, supplies or products (but not to the extent that any such availability of any of the foregoing results from SolarCity's failure to have exercised reasonable diligence); power or voltage surge caused by someone other than SolarCity including a grid supply voltage outside of the standard range specified by your utility; and failure of equipment not utilized by SolarCity or under its control.

6. **LIMITATIONS ON LIABILITY**

(a) No Consequential Damages

YOU MAY ONLY RECOVER DIRECT DAMAGES INCLUDING THOSE AMOUNTS DUE PURSUANT TO SECTIONS 2(c) AND 6(C) UNDER THIS LIMITED WARRANTY, AND IN NO EVENT SHALL SOLARCITY OR ITS AGENTS OR SUBCONTRACTORS BE LIABLE TO YOU OR YOUR ASSIGNS FOR SPECIAL, INDIRECT, PUNITIVE, EXEMPLARY, INCIDENTAL OR CONSEQUENTIAL DAMAGES OF ANY NATURE. SOME STATES DO NOT ALLOW THE EXCLUSION OR LIMITATION OF INCIDENTAL OR CONSEQUENTIAL DAMAGES, SO THE ABOVE LIMITATION MAY NOT APPLY TO YOU.

(b) Limitation of Duration of Implied Warranties

ANY IMPLIED WARRANTIES, INCLUDING THE IMPLIED WARRANTIES OF FITNESS FOR A PARTICULAR PURPOSE AND MERCHANTABILITY ARISING UNDER STATE LAW, SHALL IN NO EVENT EXTEND PAST THE EXPIRATION OF ANY WARRANTY PERIOD IN THIS LIMITED WARRANTY. SOME STATES DO NOT ALLOW LIMITATIONS ON HOW LONG AN IMPLIED WARRANTY LASTS, SO THE ABOVE LIMITATION MAY NOT APPLY TO YOU.

(c) Limit of Liability

Notwithstanding any other provision of this Limited Warranty to the contrary, SolarCity's total liability arising out of relating to this Limited Warranty shall in no event:

(i) For System Replacement: exceed the greater of (a) the sum of the Lease payments over the Term of the Lease; and (b) the original cost of the System; and

(ii) For damages to your Home, Belongings and Property: exceed two million dollars ($2,000,000).

7. **NOTICES**

All notices under this Limited Warranty shall be made in the same manner as set forth in the Lease to the addresses listed below:

TO SOLARCITY:

SolarCity Corporation
3055 Clearview Way
San Mateo, CA 94402
Attention: Warranty Claims
Telephone: 650-638-1028
Facsimile: 650-638-1029
Email: leaseadministrator@solarcity.com

TO YOU: At the billing address in the Lease or any subsequent billing address you give us.

8. **ASSIGNMENT AND TRANSFER OF THIS LIMITED WARRANTY**

SolarCity may assign its rights or obligations under this Limited Warranty to a third party without your consent, provided that any assignment of SolarCity's obligations under this Limited Warranty shall be to a party professionally and financially qualified to perform such obligation. This Limited Warranty protects only the person who leases the System. Your rights and obligations under this Limited Warranty will be automatically transferred to any person who purchases the System from you or to whom you properly transfer the Lease. This Limited Warranty contains the parties' entire agreement regarding the limited warranty of the System.

EXHIBIT 3A

STATE SPECIFIC EXCEPTIONS, TERMS AND CONDITIONS

ARIZONA

Notice to Buyers (A.R.S. §44-5004)

1. Do not sign this agreement if any of the spaces intended for the agreed terms to the extent of then available information are left blank.
2. You are entitled to a copy of this agreement at the time you sign it.
3. You may pay off the full unpaid balance due under this agreement at any time, and in so doing you shall be entitled to a full rebate of the unearned finance and insurance charges.
4. You may cancel this agreement any time prior to midnight of the third business day after the date of this transaction. See the attached notice of cancellation form on **EXHIBIT 1** for an explanation of this right.
5. It shall not be legal for the seller to enter your premises unlawfully or commit any breach of the peace to repossess goods purchased under this agreement.

DocuSign
SECURED

Certificate of Completion

Envelope Number: ADB80904286F41639348631CFA5C745E		Status: Completed
Subject: SolarCity LEASE Agreement resi		
Start Date:		
Primary Applicant:		
Source Envelope:		
Document Pages: 25	Signatures: 1	Envelope Originator:
Certificate Pages: 4	Initials: 0	SolarCity Documentation
AutoNav: Enabled		3025 Clearview Way
EnvelopeId Stamping: Enabled		San Mateo, CA 94402
		documentation@solarcity.com
		IP Address: 66.116.98.164

Record Tracking

Status: Original 9/19/2014 4:04:14 PM PT	Holder: SolarCity Documentation API documentation-api@solarcity.com	Location: DocuSign
Status: Original 9/19/2014 4:05:43 PM PT	Holder: SolarCity Documentation documentation@solarcity.com	Location: DocuSign

Signer Events	Signature	Timestamp
[redacted] Security Level: secure.solarcity.com.None ID: 679ddda0-94ba-4b08-b8c9-919f2c2bb824 9/19/2014 9:04:16 AM PT Electronic Record and Signature Disclosure: Accepted: 9/19/2014 4:04:47 PM PT ID: f6e85f7d-73fb-4d99-b1ef-6bd495cbd417	DocuSigned by: [redacted] CCF6CE77F0884D07... Using IP Address: 172.56.0.21 Signed using mobile	Sent: 9/19/2014 4:04:15 PM PT Viewed: 9/19/2014 4:04:47 PM PT Signed: 9/19/2014 4:05:40 PM PT

In Person Signer Events	Signature	Timestamp

Editor Delivery Events	Status	Timestamp

Agent Delivery Events	Status	Timestamp

Intermediary Delivery Events	Status	Timestamp

Certified Delivery Events	Status	Timestamp

Carbon Copy Events	Status	Timestamp
SolarCity Documentation API documentation-api@solarcity.com SolarCity Corporation Security Level: Email, Account Authentication (None) Electronic Record and Signature Disclosure: Not Offered ID:	COPIED	Sent: 9/19/2014 4:05:43 PM PT Viewed: 9/19/2014 4:05:43 PM PT Signed: 9/19/2014 4:05:43 PM PT

Notary Events		Timestamp

Envelope Summary Events	Status	Timestamps
Envelope Sent	Hashed/Encrypted	9/19/2014 4:04:15 PM PT
Certified Delivered	Security Checked	9/19/2014 4:04:48 PM PT
Signing Complete	Security Checked	9/19/2014 4:05:40 PM PT

Envelope Summary Events	Status	Timestamps
Completed	Security Checked	9/19/2014 4:05:40 PM PT

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By checking the 'I agree' box, you further acknowledge receipt of this Electronic Signature disclosure, agree to its terms, and consent to having all disclosures provided or made available to you in electronic form and to doing business with us electronically.

Upon accepting the terms, you will be directed to download and/or sign the electronic Disclosures associated with your lease. Once you open the Disclosures, a log is created indicating you have received and reviewed your electronic Disclosures. The log establishes a presumption that you have viewed your electronic Disclosure documents and verifies your consent to receive the Disclosures in electronic form. If you choose not to accept receipt of Disclosures electronically, we will mail paper Disclosures to you at no charge.

Please print and retain a copy of this agreement for your records.

AUTHORIZED RETURN ON EQUITY ANALYSIS - WOOLRIDGE PROXY GROUP
AUTHORIZED RETURN ON EQUITY

Woolridge Electric Proxy Group Company	Ticker	Authorized Return on Equity	S&P Credit Rating	Weighting of S&P Rankings
ALLETE, Inc.	ALE	10.38%	BBB+	8.00
Alliant Energy Corporation	LNT	10.31%	A-	7.00
Ameren Corporation	AEE	9.42%	BBB+	8.00
American Electric Power Company, Inc.	AEP	9.97%	BBB	9.00
Avista Corporation	AVA	10.06%	BBB	9.00
Black Hills Corporation	BKH	9.93%	BBB	9.00
CMS Energy Corporation	CMS	10.30%	BBB+	8.00
Consolidated Edison, Inc.	ED	9.21%	A-	7.00
Dominion Resources, Inc.	D	10.20%	BBB+	8.00
Duke Energy Corporation	DUK	10.06%	A-	7.00
Edison International	EIX	10.45%	BBB+	8.00
El Paso Electric Company	EE		BBB	
Empire District Electric Company	EDE		BBB	
Entergy Corporation	ETR	9.93%	BBB	9.00
Eversource Energy	ES	9.41%	A	6.00
FirstEnergy Corporation	FE	9.75%	BBB-	10.00
Great Plains Energy Inc.	GXP	9.50%	BBB+	8.00
IDACORP, Inc.	IDA	9.90%	BBB	9.00
MGE Energy, Inc.	MGEE	10.20%	AA-	4.00
NorthWestern Corporation	NWE	10.03%	BBB	9.00
OGE Energy Corporation	OGE	10.08%	A-	7.00
Otter Tail Corporation	OTTR	10.74%	BBB	9.00
PG&E Corporation	PCG	10.40%	BBB	9.00
Pinnacle West Capital Corporation	PNW	10.00%	A-	7.00
PNM Resources, Inc.	PNM	10.07%	BBB+	8.00
Portland General Electric Company	POR	9.60%	BBB	9.00
SCANA Corporation	SCG	10.25%	BBB+	8.00
Westar Energy, Inc.	WR			
Xcel Energy Inc.	XEL	9.86%	A-	7.00
MEAN		10.00%	BBB+	7.96
LOW		9.21%	AA-	4.00
HIGH		10.74%	BBB-	10.00
Average of A-rated companies		9.93%	A-	
UNS Electric		9.50%	A-	

EXHIBIT
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AUTHORIZED RETURN ON EQUITY - UTILITY OPERATING COMPANIES

Company Name	Ticker	Type	States of Operation	Year Completed	Docket No.	Authorized Return on Equity
ALLETE (Minnesota Power)	ALE	Electric	Minnesota	2010	D-E-015/GR-09-1151	10.38%
Interstate Power & Light Co.	LNT	Electric	Iowa	2010	D-RPU-2010-0001	10.44%
Interstate Power & Light Co.	LNT	Natural Gas	Iowa	2012	D-RPU-2012-0002	10.00%
Wisconsin Power and Light Co	LNT	Electric	Wisconsin	2014	D-6680-UR-119 (Elec)	10.40%
Wisconsin Power and Light Co	LNT	Natural Gas	Wisconsin	2014	D-6680-UR-119 (Gas)	10.40%
Ameren Illinois	AEE	Electric	Illinois	2015	D-15-0305	9.14%
Ameren Illinois	AEE	Natural Gas	Illinois	2015	D-15-0142	9.60%
Union Electric Co.	AEE	Electric	Missouri	2015	C-ER-2014-0258	9.53%
Appalachian Power Co.	AEP	Electric	Virginia	2014	C-PUE-2014-00026	9.70%
Appalachian Power Co.	AEP	Electric	West Virginia	2015	C-14-1152-E-42T	9.75%
Indiana Michigan Power Co.	AEP	Electric	Indiana	2013	Ca-44075	10.20%
Indiana Michigan Power Co.	AEP	Electric	Michigan	2012	C-U-16801	10.20%
Ohio Power Co.	AEP	Electric	Ohio	2011	C-11-0352-EL-AIR	10.30%
Southwestern Electric Power Co	AEP	Electric	Louisiana	2013	D-U-32220	10.00%
Southwestern Electric Power Co	AEP	Electric	Texas	2013	D-40443	9.65%
Avista Corp.	AVA	Electric	Idaho	2015	C-AVU-E-15-05	9.50%
Avista Corp.	AVA	Natural Gas	Idaho	2015	C-AVU-G-15-01	9.50%
Avista Corp.	AVA	Natural Gas	Oregon	2015	D-UG-284	9.50%
Avista Corp.	AVA	Electric	Washington	2016	D-UE-150204	9.50%
Avista Corp.	AVA	Natural Gas	Washington	2016	D-UG-150205	9.50%
Alaska Electric Light Power	AVA	Electric	Alaska	2011	D-U-10-029	12.88%
Black Hills Colorado Electric	BKH	Electric	Colorado	2014	D-14AL-0393E	9.83%
Black Hills Nebraska Gas	BKH	Natural Gas	Nebraska	2010	D-NG-0061	10.10%
Cheyenne Light Fuel Power Co.	BKH	Electric	Wyoming	2014	D-20003-132-ER-13	9.90%
Cheyenne Light Fuel Power Co.	BKH	Natural Gas	Wyoming	2014	D-30005-182-GR-13	9.90%
Consumers Energy Co.	CMS	Electric	Michigan	2015	C-U-17735	10.30%
Consumers Energy Co.	CMS	Natural Gas	Michigan	2015	C-U-17643	10.30%
Consolidated Edison Co. of NY	ED	Electric	New York	2015	C-15-E-0050/C-13-E-0030 (Ext)	9.00%
Consolidated Edison Co. of NY	ED	Natural Gas	New York	2014	C-13-G-0031	9.30%
Orange & Rockland Utlts Inc.	ED	Electric	New York	2015	C-14-E-0493	9.00%
Orange & Rockland Utlts Inc.	ED	Natural Gas	New York	2015	C-14-G-0494	9.00%
Rockland Electric Company	ED	Electric	New Jersey	2014	D-ER-13111135	9.75%
Virginia Electric & Power Co.	D	Electric	North Carolina	2012	D-E-22, Sub 479	10.20%
Duke Energy Carolinas LLC	DUK	Electric	North Carolina	2013	D-E-7, Sub 1026	10.20%
Duke Energy Carolinas LLC	DUK	Electric	South Carolina	2013	D-2013-59-E	10.20%
Duke Energy Ohio Inc.	DUK	Electric	Ohio	2013	C-12-1682-EL-AIR	9.84%
Duke Energy Ohio Inc.	DUK	Natural Gas	Ohio	2013	C-12-1685-GA-AIR	9.84%
Duke Energy Progress LLC	DUK	Electric	North Carolina	2013	D-E-2, Sub 1023	10.20%
Southern California Edison Co.	EIX	Electric	California	2012	Ap-12-04-015	10.45%
Entergy Arkansas Inc.	ETR	Electric	Arkansas	2016	D-15-015-U	9.75%
Entergy Gulf States LA LLC	ETR	Electric	Louisiana	2013	D-U-32707	9.95%
Entergy Louisiana LLC	ETR	Electric	Louisiana	2014	D-UD-13-01	9.95%
Entergy Mississippi Inc.	ETR	Electric	Mississippi	2014	D-2014-UN-0132	10.07%
Connecticut Light & Power Co.	ES	Electric	Connecticut	2014	D-14-05-06	9.17%
NSTAR Gas Co.	ES	Natural Gas	Massachusetts	2015	DPU 14-150	9.80%
Public Service Co. of NH	ES	Electric	New Hampshire	2010	D-DE-09-035	9.67%
Western Massachusetts Electric	ES	Electric	Massachusetts	2011	DPU 10-70	9.60%
Yankee Gas Services Co.	ES	Natural Gas	Connecticut	2011	D-10-12-02	8.83%
Jersey Cntrl Power & Light Co.	FE	Electric	New Jersey	2015	D-ER-12111052	9.75%
Kansas City Power & Light	GXP	Electric	Kansas	2015	D-15-KCPE-116-RTS	9.30%
Kansas City Power & Light	GXP	Electric	Missouri	2015	C-ER-2014-0370	9.50%
KCP&L Greater Missouri Op Co	GXP	Electric	Missouri	2013	C-ER-2012-0175 (MPS)	9.70%
Idaho Power Co.	IDA	Electric	Oregon	2012	D-UE-233	9.90%
Madison Gas and Electric Co.	MGEE	Electric	Wisconsin	2014	D-3270-UR-120 (Elec)	10.20%
Madison Gas and Electric Co.	MGEE	Natural Gas	Wisconsin	2014	D-3270-UR-120 (Gas)	10.20%
NorthWestern Corp.	NWE	Electric	Montana	2010	D-D2009.9.129 (elec)	10.25%
NorthWestern Corp.	NWE	Natural Gas	Montana	2013	D-D2012.9.94	9.80%
Oklahoma Gas and Electric Co.	OGE	Electric	Arkansas	2011	D-10-067-U	9.95%
Oklahoma Gas and Electric Co.	OGE	Electric	Oklahoma	2012	Ca-PUD201100087	10.20%
Otter Tail Power Co.	OTTR	Electric	Minnesota	2011	D-E-017/GR-10-239	10.74%
Pacific Gas and Electric Co.	PCG	Electric	California	2012	Ap-12-04-018 (Elec)	10.40%
Pacific Gas and Electric Co.	PCG	Natural Gas	California	2012	Ap-12-04-018 (Gas)	10.40%
Arizona Public Service Co.	PNW	Electric	Arizona	2012	D-E-01345A-11-0224	10.00%
Public Service Co. of NM	PNM	Electric	New Mexico	2011	C-10-00086-UT	10.00%
Texas-New Mexico Power Co.	PNM	Electric	Texas	2011	D-38480	10.13%
Portland General Electric Co.	POR	Electric	Oregon	2015	D-UE-294	9.60%
South Carolina Electric & Gas	SCG	Electric	South Carolina	2012	D-2012-218-E	10.25%
South Carolina Electric & Gas	SCG	Natural Gas	South Carolina	2014	D-2014-6-G	10.25%
Northern States Power Co. - MN	XEL	Electric	Minnesota	2015	D-E-002/GR-13-868	9.72%
Northern States Power Co. - MN	XEL	Natural Gas	Minnesota	2010	D-G-002/GR-09-1153	10.09%
Northern States Power Co. - MN	XEL	Electric	North Dakota	2014	C-PU-12-813	9.75%
Northern States Power Co - WI	XEL	Electric	Wisconsin	2015	D-4220-UR-121 (Elec)	10.00%
Northern States Power Co - WI	XEL	Natural Gas	Wisconsin	2015	D-4220-UR-121 (Gas)	10.00%
Public Service Co. of CO	XEL	Electric	Colorado	2015	D-14AL-0660E	9.83%
Public Service Co. of CO	XEL	Natural Gas	Colorado	2013	D-12AL-1268G	9.72%
Southwestern Public Service Co	XEL	Electric	New Mexico	2014	C-12-00350-UT	9.96%
Southwestern Public Service Co	XEL	Electric	Texas	2015	D-43695	9.70%

Notes:

[1] Operating Subsidiaries with rate cases not covered by SNL Financial were excluded from the analysis.
[2] Operating Subsidiaries with rate cases that were silent with respect to traditional rate case parameters were excluded from the analysis.
[3] Excludes Operating Subsidiaries with most recent rate case prior to 2010.
[4] Kansas Gas and Electric Co. was labeled as Westar Energy Inc. since the two companies file rate cases jointly.