ORIGINAL

NEW APPLICATION

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2013 JUL 12 P 4: 17
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BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED
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IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF NET METERING COST SHIFT SOLUTION	DOCKET NO. E-01345A-13-0248 **APPLICATION**

Rooftop solar installations have increased significantly each year in APS's service territory since January 2009. In January 2009, there were approximately 900 systems installed. As of June 2013, that number has grown to over 18,000 and continues to grow at approximately 500 new rooftop solar systems each month. APS has been proud to help customers install so much solar generation capacity and we look forward to the continued strong growth of solar in Arizona.

But this future is threatened by current Net Metering policy in Arizona. As a result of Net Metering, residential customers with rooftop solar do not pay for most of the electric services that they use. These costs are then paid by other customers—through higher rates—who can't install or don't want rooftop solar. This shifting of costs is unfair. It is also growing with every solar installation, and needs to be addressed now before it becomes too large to fix with a balanced solution.

APS is not alone. This issue has gained national attention as utilities across the country work to address this growing cost shift. In Arizona, APS has been seeking stakeholder input to understand the issue from all perspectives and develop a fair solution that can be implemented now, in a way that preserves the opportunity for customers to install solar. With input gathered from a wide spectrum of interested parties and an evaluation of similar efforts nationally, APS now submits this Application to update Net Metering and distributed energy policy and requests that the Commission:

- Select either the Net Metering Option or the Bill Credit Option, as described below, as the Net Metering construct for which residential customers installing new distributed energy will be eligible;
- "Grandfather" the use of current Net Metering rules by existing and immediately pending distributed energy customers (as described below); and
- Approve the continued use of direct cash incentives to new solar customers in the form of upfront cash incentives to ensure flexibility and transparency.

APS's proposal pertains to residential customers only—Net Metering would continue for commercial and industrial customers in its current form. This Application is supported by the attached Direct Testimony of Messrs. Jeffrey Guldner, Gregory Bernosky and Charles Miessner.

I. BACKGROUND REGARDING DISTRIBUTED ENERGY AND NET METERING

Arizona's Renewable Energy Standard Tariff (REST) became effective in 2007. It requires APS to acquire 15% of the energy it uses to serve retail load from renewable sources by 2025. About a third of that requirement must come from distributed energy (DE), such as rooftop solar. This is referred to as the "DE carve out," and must be met in equal measures by commercial and residential DE systems. As of this Application, more than 18,000 APS customers have installed rooftop solar systems. This is enough rooftop solar for APS to comply with the residential DE carve out through 2016 with no further rooftop solar installations.[1]

A. The Incentives Sustaining DE Penetration Include Federal and State Tax Credits, Direct Cash Payments and Net Metering.

This accelerated level of compliance with the DE carve out has been driven by both direct and indirect incentives that subsidize the installation of rooftop solar. Solar panel prices have decreased dramatically. But it is widely recognized that rooftop solar is more expensive to install and less efficient than other types of renewable generation, including utility-scale solar (i.e., larger solar power plants). Without incentives, rooftop solar is not economical for customers.

One of the explicit incentives driving rooftop solar installations comes in the form of tax incentives. A federal Investment Tax Credit is available to rooftop solar owners and provides a financial benefit amounting to 30% of a solar project's value.[2] In addition, Arizona offers multiple tax credits, including property and sales tax exemptions, as well as a tax credit for installing solar.[3] More central to this Application, however, are the subsidies underlying rooftop solar that fall under the Commission's authority: direct cash incentives and Net Metering policy.

B. Direct Cash Incentives Have Declined Since Their Inception, But Customer Participation in DE Has Increased.

APS offers direct cash incentives to residential customers through its annual REST program. These incentives are paid in a lump sum when the system is installed and are called upfront cash incentives, or UFIs. As outlined in Mr. Bernosky's testimony, APS offered a UFI of $3.00/watt to residential customers installing rooftop solar in 2008. Assuming an average system size of 7 kW, this amounted to a UFI of $21,000 per system. UFIs have steadily declined since that time, falling to $1.75/watt by the end of 2010 and $0.75/watt by the end of 2011. By the end of 2012, direct cash

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[1] Sufficient commercial DE is installed for APS to meet the commercial DE carve out through 2020.
[2] *See* 26 U.S.C. § 25D.
[3] *See, e.g.*, A.R.S. § 43-1083 (extending tax credit worth up to 25% of a solar system to a maximum of $1,000); A.R.S. § 42-5061, 5063 & 5075 (exempting the sale of renewable energy from sales tax).

incentives to residential customers had fallen to $0.10/watt. As this decline in incentives levels occurred, however, customer participation in DE was ramping up.

C. Net Metering Has Been Enough of a Subsidy to Sustain DE Solar Installations, Even With Direct Cash Payments.

When the Commission first began discussing Net Metering, APS raised concerns regarding the cost shift caused by Net Metering.[4] Nonetheless, APS began offering Net Metering to customers as a pilot program pursuant to Commission direction soon after the REST became effective. Statewide Net Metering rules subsequently became effective in May 2009 and APS's Net Metering rate rider (EPR-6) became effective a few months later.

Since the beginning of Net Metering, the incentives inherent in the Commission's Net Metering policy have become increasingly more relevant than UFIs. In fact, the substantial incentive paid to Net Metering customers, along with declines in the cost of solar installations, has been more than sufficient to compensate for this decline in direct cash incentives. The incentive embedded in Net Metering, however, does not reflect the value that solar generation provides to the electric system. So for in 2013, the size of the Net Metering incentive is driving approximately 500 customers a month to install rooftop solar—far more than needed to comply with the DE carve out. And because Net Metering allows customers installing rooftop solar to avoid paying for infrastructure they rely on and services they use, these installations come at a cost to APS's remaining non-solar customers. With each customer taking service under Net Metering, more costs are shifted unwittingly onto those who can't install or don't want rooftop solar.

II. NET METERING: HOW IT WORKS

As described in the attached testimony of Mr. Miessner, Net Metering is a customer program that APS offers, as do many other utilities in one form or another. Under Net Metering, customers who install rooftop solar can supply a portion of their

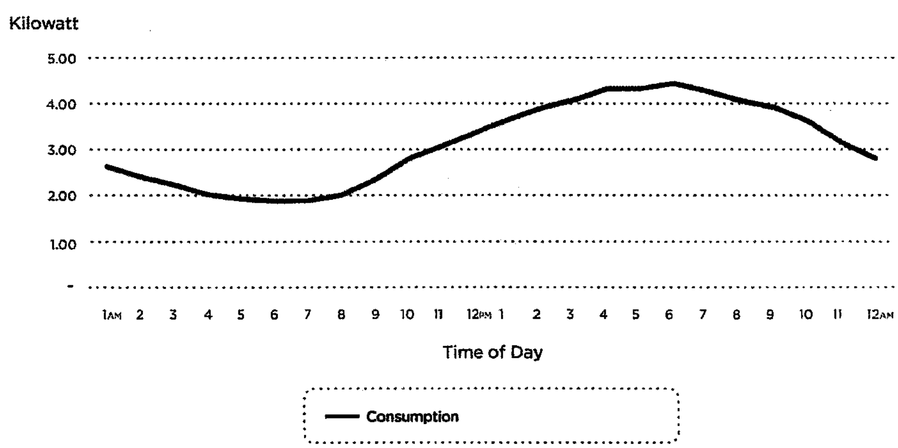
[4] *See, e.g.,* Decision No. 69663, pp. 87-89 (June 2007).

own electric power generation. In addition to self-supplying, customers with rooftop solar at times produce more electric power than they use. This extra energy is called Export Energy, and is exported onto the electrical grid. Both the self-supply and Export Energy permitted by Net Metering provide solar customers with substantial monetary benefits.

A. Customers Who Install Rooftop Solar Receive a Monetary Benefit by Supplying a Portion of Their Own Energy.

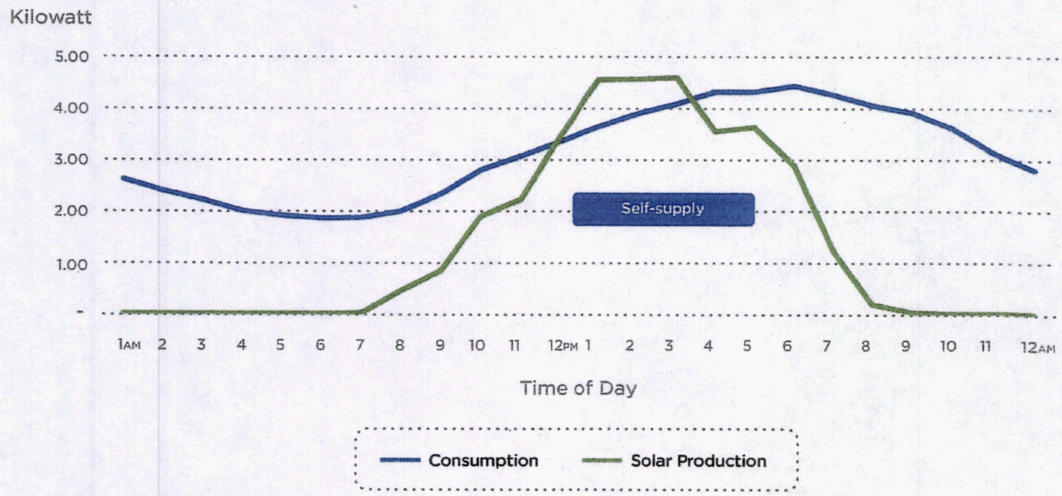
Rooftop solar produces varying amounts of power during the daytime. When a customer installs rooftop solar, they are able to use any power produced by their solar system rather than take power from the electricity grid. For example, Figure 1 shows the electricity used by an actual (typical) residential customer over a 24-hour period:

FIGURE 1: TYPICAL CUSTOMER USAGE



When this customer installs solar, however, they are able to supply a portion of their energy usage as shown in Figure 2:

FIGURE 2: ENERGY SELF-SUPPLIED BY DE

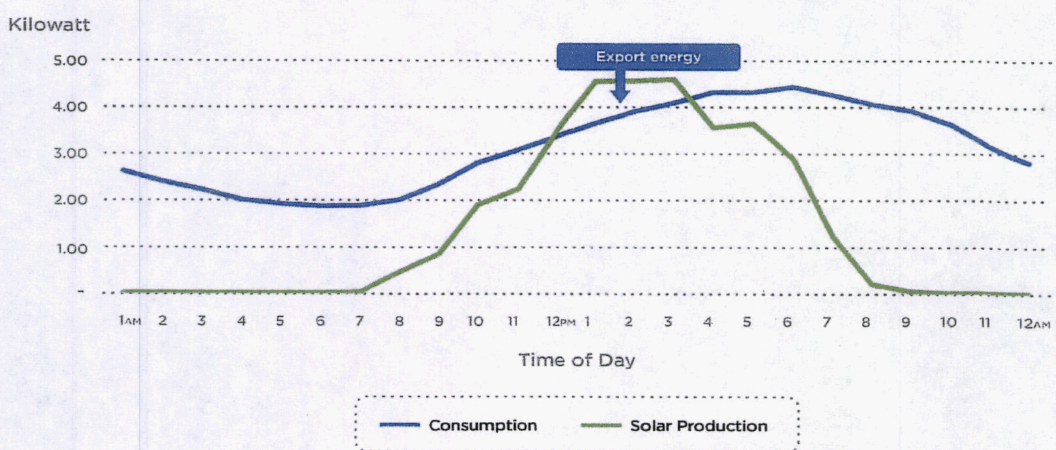


The ability to supply their own power, while taking service on a rate that collects almost all electric service costs through charges based on total energy consumed, provides a monetary benefit to solar customers. It permits them to avoid paying almost their entire electric bill. This is true even though they continue to rely on and use the electricity grid. The ability to sell Export Energy back to APS furthers this monetary benefit.

B. Solar Customers Also Receive a Monetary Benefit from Export Energy.

A customer with rooftop solar typically produces Export Energy as shown in Figure 3:

FIGURE 3: EXCESS ENERGY EXPORT UNDER NET METERING

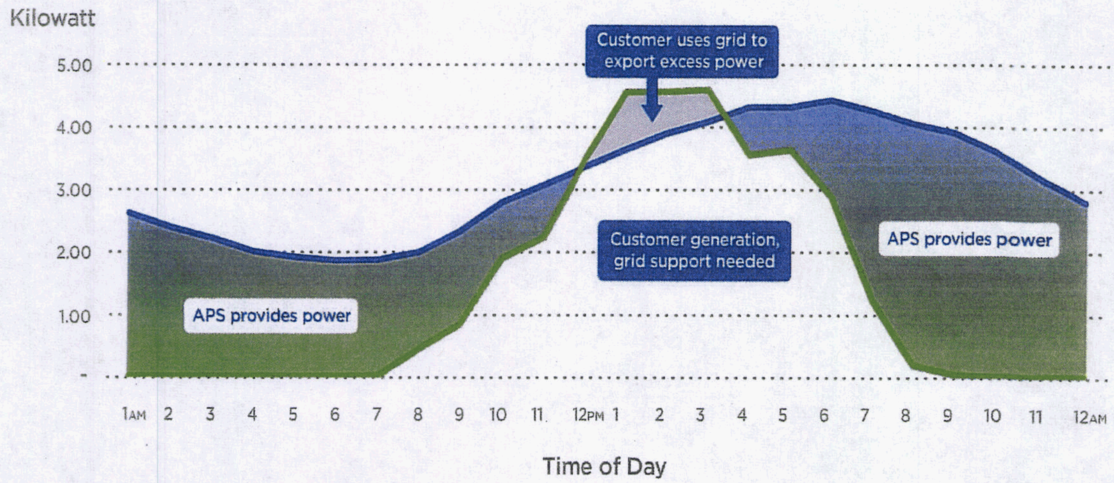


As Export Energy is created, the customer's meter keeps track of how much electricity is "exported" to the grid. The amount of exported electricity is then credited against the customer's bill, subtracting from the bill energy that the customer actually took from the grid at other times of the day. In effect, the customer uses the grid as a battery by exporting energy at one time of day and "using" it through the application of the bill credit at other times. But for this bill credit, the customer would have paid the full retail rate for the energy subtracted from their bill. In other words, customers effectively sell Export Energy to APS at the full retail rate at a time when APS could produce or purchase in the wholesale market the same amount of power at a much lower cost.

III. NET METERING: HOW IT SHIFTS COSTS

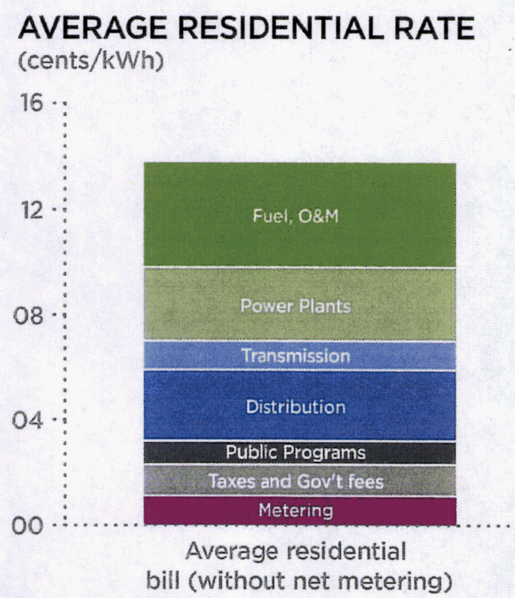
Customers with rooftop solar systems use the electric grid twenty-four hours a day. When the rooftop solar system is not producing energy—such as when the sun sets—they receive power generated and delivered by APS. Even when the rooftop system is producing power, however, customers with rooftop solar systems still use the grid to receive other forms of electric service. These services include (i) immediate and reliable access to energy when the rooftop system doesn't produce enough energy to meet 100% of the customer's needs; (ii) a connection to the grid onto which they can export power when their system is producing more than needed by the customer; (iii) providing power quality and stability (*e.g.*, voltage and VAR support) for the customer without which the rooftop solar system would not work; and (iv) providing back up power so that when the rooftop solar system suddenly stops producing, such as when clouds pass overhead, the customer's electricity supply continues without even a momentary interruption. Figure 4 graphically demonstrates how rooftop solar customers use and rely on the grid twenty-four hours a day:

FIGURE 4: TYPICAL GRID INTERACTION FOR ROOFTOP SOLAR



Even though Net Metered customers constantly rely on and use the grid to receive various forms of electric service, the vast majority do not pay for those services. A typical residential bill is structured so that the charges paid contribute to the system's costs as shown in Figure 5:

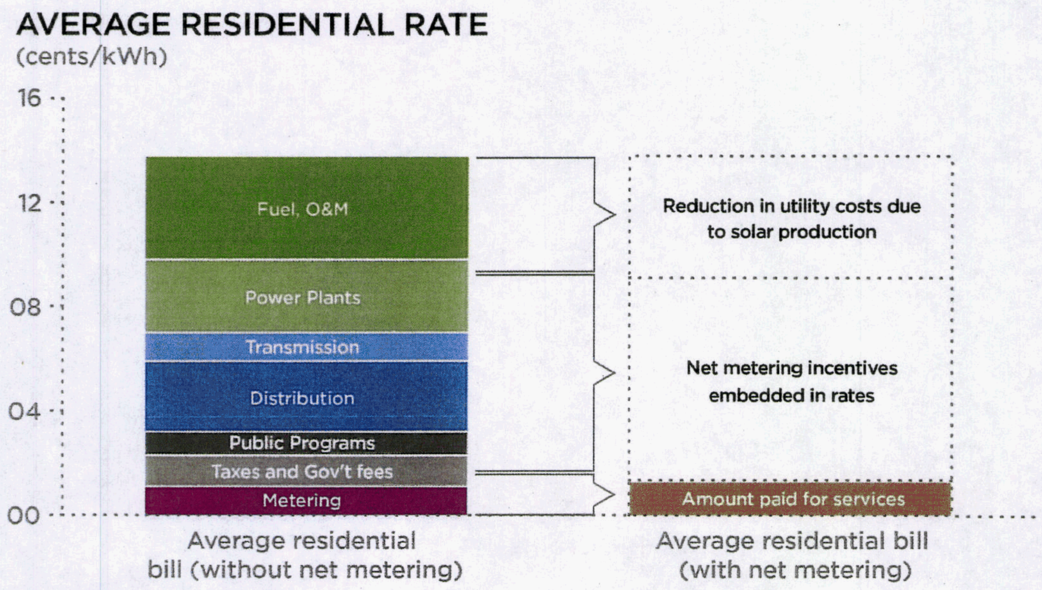
FIGURE 5: TYPICAL COST CATEGORIES IN RESIDENTIAL BILL



The components of this average bill reflect each category of costs required to supply electric service to customers. A residential customer's contribution to these costs occurs through energy usage charges. In other words, the amount of a residential customer's contribution to fixed costs is based on their energy usage.

But Net Metering allows customers to avoid paying for these fixed costs. As described in Mr. Miessner's testimony and shown in Figure 6, customers with rooftop solar avoid contributing to every category of fixed costs except metering:

FIGURE 6: COST CATEGORIES AVOIDED WITH NET METERING



Through Net Metering, customers with rooftop solar are able to avoid paying for services they use by (i) staying on an "energy only" rate and supplying their own power; and (ii) reducing the total usage on their monthly bill by applying an Export Energy credit.

Because APS rates are established and authorized by the Commission on a "cost of service" model, the fixed costs avoided by customers with rooftop solar are shifted to customers without solar. On average, the cost shift each year is approximately $1,000 per rooftop solar system. That means higher electricity rates for customers without solar. This cost shift is unfair. And as more customers install solar, the cost shift will continue to grow. Today, the total costs shifted to non-solar customers are approximately $18 million. Each year, that amount could increase by an estimated $6-$10 million.

FIGURE 7: THE GROWING COST SHIFT

500	$1,000	$18M	$6-10M
Number of new net metered customers added each month	*Costs a typical solar customer avoids per year for services they still use*	*Approximate current costs being shifted to non-solar customers today*	*Approximate cost growth added annually for every year this is unresolved*

The expanding magnitude of this problem requires that action be taken now, rather than waiting for more costs to accumulate and be shifted to customers without solar. It would be irresponsible for APS to stay silent as the magnitude of this cost shift—and resulting consequence to customers—grows. Failure to act now could prompt significant rate increases on customers without solar. It may also preclude the Commission from grandfathering the use of Net Metering by customers that currently have solar installed on their homes. Acting now is the best means to limit the amount of shifted costs and preserve the ability to grandfather existing customers with solar.

IV. APS SOLICITED STAKEHOLDER INPUT THROUGH A MULTI-SESSION TECHNICAL CONFERENCE

In preparation for this Application, APS hosted a multi-session Technical Conference in the first half of 2013 to evaluate the costs and benefits of DE and Net Metering. APS hired a third party—Power Pundits—to facilitate the Conference and invited all interested stakeholders to attend. Throughout the Conference, 175 people attended representing a diverse group of stakeholders that included solar installers, developers and policy advocates, customers, utility representatives, academics, consultants, researchers and Commission representatives. Experts from both utilities and the solar industry presented their perspectives on DE and Net Metering. APS voluntarily responded to over 175 requests for technical information and posted those responses, as well as all Technical Conference presentations and studies, on a website for all to access.[5] The results of the Technical Conference, including detail regarding the various stakeholder perspectives, are contained in a summary that was filed on July 9, 2013 in Docket No. E-01345A-12-0290, and is attached to this Application as Exhibit 4.

In connection with the Technical Conference, APS retained SAIC Energy, Environment and Infrastructure, LLC (SAIC), an international group comprised of preeminent economic and utility analysts, to update a prior study regarding the benefits of DE. Using a methodology developed with and approved by the solar industry in 2009, SAIC analyzed the possible benefits of rooftop solar through 2025. The study focused on predicted future operational benefits and relied on the impacts of DE seen now on APS's system to develop those predictions. The SAIC study concluded that rooftop solar provides benefits by reducing (i) fuel expenditures; and (ii) a modest amount of power plant costs. Because solar customers use the grid, however, rooftop solar does not avoid or reduce any other costs required to build, operate and maintain power plants or electrical wires.

V. TOWARDS A SOLUTION: USING EXISTING RATES TO TRANSPARENTLY BALANCE COSTS AND BENEFITS

Informed by analysis conducted in other jurisdictions, the SAIC study and stakeholder input received during the Technical Conference, APS began developing a solution to the cost shift in earnest. In developing the solution, APS was guided by four key principles:

(i) Ensure fairness in addressing the cost shift;

(ii) Make transparent any incentives underlying the installation of rooftop solar;

(iii) Minimize costs to customers; and

(iv) Craft a solution that will be robust and adaptable over the long term.

Before arriving at the two options described below, APS considered several possible solutions, all of which fell into one of two groups.

[5] *See* www.solarfutureArizona.com

The first group of solutions involved the use of new and existing retail rate schedules to more appropriately recover the cost to serve customers with rooftop solar and minimize the cost shift to non-solar customers. Options under this category continued the use of Net Metering and emphasized the use of the basic service charge, a demand charge or a standby charge.

The second group of options involved moving from Net Metering to a mechanism in which solar customers pay for all of the energy they consume, but receive a bill credit for 100% of the energy produced by their rooftop solar system. This concept is similar to models used by a few other utilities. The key variable in this group of options concerned the method for setting the price paid to customers for the rooftop solar energy produced. Those methods generally involved setting either a market-based price, or a price based on non-market, value-based concepts.

Drawing from each group, APS proposes two possible solutions as described in Mr. Miessner's testimony and summarized below. To create a sustainable way for DE solar to continue growing in a way that is fair to all customers, APS proposes that the Commission select one of two proposed options. Based on the Commission's selection, any new APS residential customer installing DE (who is not grandfathered) would either: (i) take service under APS's existing ECT-2 rate and use Net Metering (the Net Metering Option); or (ii) take service under the customer's current rate and receive a bill credit for 100% of the DE system's production at a market-based price for power (the Bill Credit Option). Neither solution involves creating a new rate or increasing rates for any customers. This proposal involves the Commission selecting only one of the options. Due to a number of complications (including those related to incentives), it would be impractical to simultaneously offer both options to customers. These options offer different advantages as described below.

A. The Net Metering Option: ECT-2 Plus Net Metering

With this option, any residential customer installing a new DE system would only be eligible to take electric service under APS's ECT-2 rate. ECT-2 is a demand-based rate that approximately 100,000 APS customers currently use. ECT-2 better balances the collection of fixed costs between usage-based energy charges and demand-based charges, which would allow APS to more accurately charge rooftop solar customers for the services they use. Under the Net Metering Option, customers installing a new DE system would continue to be eligible for APS's current Net Metering Rate Rider. Because customers would still be eligible for Net Metering, and ECT-2 still partially relies on usage charges for collecting fixed costs, this option is an imperfect solution as more fully described in Mr. Miessner's testimony. Nonetheless, the Net Metering Option will meaningfully address the cost shift in a sustainable and fair manner.

B. The Bill Credit Option

Under this option, customers can remain on any APS rate plan for which they are otherwise eligible. Instead of Net Metering, APS would compensate rooftop solar customers through a bill credit for all of the power produced by their rooftop systems. The amount of the credit would be based on the forward market at Palo Verde with adjustments, as described in Mr. Miessner's testimony. This price would send a more accurate price signal for the true cost of the electrical services provided to potential rooftop solar customers. Under this option, new customers with rooftop solar would more appropriately contribute to the fixed costs needed to provide them with electric service because their bill would be directly reduced by a credit reflecting the amount paid for their solar generation, rather than indirectly reduced through a lowering of their energy consumption.

VI. APS PROPOSES GRANDFATHERING CURRENT AND IMMEDIATELY PENDING DE CUSTOMERS

APS proposes that whichever option the Commission selects, it only applies prospectively. To manage this prospective application, APS proposes grandfathering existing rate constructs (i.e., a customer's existing rate and use of Net Metering) for residential customers who (i) have DE installed on their homes now; or (ii) submit an application and signed contract with a solar installer to APS by October 15, 2013. The grandfathering would extend for a maximum of 20 years from the effective date of the Commission's decision in this matter and would not be transferable to a new customer at the same premise.

VII. INCENTIVES UNDER APS'S PROPOSAL

Today, avoiding the payment of fixed costs, like distribution and transmission, provides a major part of the monetary value underlying most DE transactions. Both the Net Metering and Bill Credit Options are designed to better align a solar customer's fixed cost contribution with the electric services they receive. But until the cost of solar declines further, both options will change the economics of DE transactions and could result in a slower pace of residential rooftop solar installations.

Slowing the pace of DE installations will not jeopardize Arizona's ability to achieve its energy goals in the near term. Residential customers have installed sufficient rooftop solar on APS's system to ensure that APS will comply with these requirements through 2016. Nonetheless, APS believes that the Commission should consider the use of up-front cash incentives to encourage additional DE penetration after selecting either the Net Metering or Bill Credit Option. APS proposes a few parameters for those incentives in the interest of promoting a transparent and sustainable incentive structure as described in Mr. Bernosky's testimony and summarized below.

First, APS proposes that all direct cash incentives be in the form of up-front incentives only. Up-front incentives have historically been the only direct cash incentive available to residential customers, and they offer a transparent, flexible means to incentivize installations. They are paid only once, and can be finely tuned in response to changes in market conditions.

Second, APS proposes that incentive levels be modified more frequently than the current approach through the annual REST Plan. Incentives should change with market conditions and be as flexible as possible. Based on APS's experience with incentives, flexibility is needed so that incentive levels stay aligned with, rather than exceeding or falling short of, desired adoption. Incentive adjustments could occur through various means as described in Mr. Bernosky's testimony. APS does not propose any specific mechanism for adjusting incentives, but expects that stakeholders can offer valuable insight.

VIII. CONCLUSION

Solar energy offers a great opportunity for Arizona—one that APS and its customers have vigorously pursued under the Commission's direction. One need only look at the facts to get a sense of APS's commitment to solar. APS is ranked fourth amongst utilities in the nation for the amount of solar in its service territory and is second only to California for the amount of solar installed in a state.

But this great success is at risk. The growing magnitude of costs being shifted to customers without solar is unsustainable. These costs will inevitably push rates higher and higher for customers without solar. These rate increases, however, will not reflect a transparent and equitable distribution of costs and benefits. This is unfair, and needs to be addressed now, before the consequences of the cost shift become unmanageable.

The two proposed options offer the best means to avoid this outcome and preserve the future of solar through a transparent balancing of costs and benefits. Accordingly, APS respectfully requests that the Commission:

(i) Select either the Net Metering Option or the Bill Credit Option, as described in this Application and the attached testimony;

(ii) Grandfather the rates and use of Net Metering by existing and immediately pending DE customers as described in this Application and the attached testimony;

(iii) Implement an incentive structure as described in this Application and the attached testimony, should the Commission choose to order the direct payment of cash to incentivize residential DE installations;

(iv) Address this matter on an expedited basis; and

(v) Grant any waivers or other forms of relief that the Commission deems appropriate.

RESPECTFULLY SUBMITTED this 12th day of July, 2013.

By: ______________________
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ORIGINAL and thirteen (13) copies
of the foregoing filed this 12th day of
July, 2013, with:

Docket Control
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Phoenix, Arizona 85007

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EXHIBIT 1

TESTIMONY OF JEFFREY B. GULDNER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-13-xxxx

July 12, 2013

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TESTIMONY OF JEFFREY B. GULDNER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
Docket No. E-01345A-13-XXXX

I. <u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Jeffrey B. Guldner. My business address is 400 N. 5th Street, Phoenix, Arizona 85004. I am Senior Vice President, Customers and Regulation for Arizona Public Service Company (APS or Company). I am responsible for customer service, rates and pricing, regulatory policy, and regulatory compliance matters before the Arizona Corporation Commission (Commission) and the Federal Energy Regulatory Commission that affect the Company and our customers.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I joined APS in 2004 as Director of Regulatory Compliance, then assumed responsibility for federal regulation and policy at the Company, and in early 2012 also assumed responsibility for customer service. Prior to joining APS, I was a partner in the Phoenix, Arizona offices of Snell & Wilmer LLP, where I practiced energy and public utilities law. I received a J.D., *magna cum laude*, from Arizona State University and a B.A. from the University of Iowa.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I describe APS's continued commitment to solar generation and explain how current policy is threatening the sustainability of solar and distributed energy programs at APS. I discuss why the current policy, if not addressed now, will continue to increasingly burden APS customers who cannot or do not participate in distributed energy programs. I then present an overview of APS's proposed solution for maintaining a fair and sustainable renewable energy policy in the state of Arizona.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. APS has over 60 years of experience in researching, developing, testing, and integrating solar generation and other renewable resources, making the Company one of the leading utilities involved in the adoption and promotion of solar energy. The significant potential of solar-generated electric energy in Arizona, along with the availability of incentives intended to encourage distributed energy installations, has caused APS customers to adopt rooftop solar generating systems in record numbers over the past two years.

However, the programs and policies currently in place to encourage adoption of solar distributed energy have created an unfair and unsustainable cost shift between those customers who install rooftop solar and those customers who do not or cannot. Under the Commission's current Net Metering rules, customers without distributed generation are paying higher rates in order to provide benefits to Net Metering customers. This cost shift cannot be sustained as market penetration of distributed solar rooftop systems continues to increase.

Current regulatory policy results in the distributed energy customer receiving electric services at essentially no cost, a clearly inequitable and unreasonable policy. The Company is therefore proposing a fairer and non-discriminatory solution that will limit this cost shift and will ensure the viability and sustainability of solar rooftop and other renewable generating systems into the future.

III. APS'S SOLAR LEADERSHIP

Q. IS APS A LEADER IN SOLAR DEVELOPMENT?

A. Yes. Since the Company hosted one of the first solar conferences in this country in 1954, APS has encouraged solar development in Arizona and the greater Southwest through research in solar generation applications, participation in industry trials and in various solar generation ventures with other utilities. The Company has also worked with stakeholders and interested parties to create programs and tariffs that encourage customer adoption of solar applications. Through these efforts, opportunities for customers, solar developers, and solar installers have flourished.

Q. PLEASE DESCRIBE APS'S CURRENT COMMITMENT TO SOLAR.

A. By the end of 2013, APS will have interconnected almost 700 megawatts of solar generation to its transmission and distribution system. This generation consists of large solar facilities built by developers and owned by APS, customer installed distributed generation such as solar rooftop systems, and power purchased from solar installations owned by third party generation providers.

Q. WILL APS'S PROPOSAL CHANGE THIS COMMITMENT?

A. No. In fact, APS's proposal today is a direct result of the outstanding success of distributed energy policy in Arizona. It is necessary now to build upon that success in a sustainable way. The rapidly escalating adoption of rooftop solar installations in the Company's service territory over the past two years has changed the face of the solar landscape in Arizona. This increase in adoption rates has taken place as a result of decreasing solar panel cost, evolving industry sales models, federal and state investment credits, and the availability of utility rate and cash incentives. However, the underlying regulatory policies driving this success have not evolved in parallel, creating an unsustainable divergence of policy and reality.

IV. <u>THE DISTRIBUTED ENERGY ISSUE</u>

Q. WHY DOES APS BELIEVE CURRENT DISTRIBUTED ENERGY POLICY IS NOT SUSTAINABLE?

A. The policies surrounding residential distributed energy installations today have created a subset of customers that are able to avoid paying for infrastructure and services that they rely on and use. These customers are also able to avoid paying their proportionate share of Commission approved charges such as the Demand-Side Management Adjustment Charge, the System Benefits Charge, the Lost Fixed Cost Recovery Mechanism, and other taxes and assessments.

Because APS is a cost-of-service regulated utility, costs that are not paid by a distributed energy customer are eventually paid by those customers who do not or cannot choose to install distributed generating systems. As more and more customers install these systems without changes to underlying policy, the cost of infrastructure and services will be paid by a smaller and smaller group of customers, causing higher rates for customers without solar. This snowball effect cannot be sustained in the long term.

Q. HOW DOES THIS HAPPEN?

A. Customers who have installed rooftop solar supply a portion of their own energy needs directly from the installed system, reducing the energy supplied from the utility. However, traditional utility rates (especially for residential customers) are designed to recover the vast majority of the cost to provide service to customers through a kWh energy charge—the precise charge that distributed energy customers avoid while their system generates power. But distributed energy customers nonetheless use wires, poles, and other electric supply infrastructure, whether the customer is buying from or selling to the Company. As a result, distributed energy customers avoid paying for those infrastructure and services they use by supplying only a portion of their own energy needs.

Distributed generation customers also avoid paying for infrastructure even when they aren't providing their own energy. When a distributed energy system produces energy over and above the energy needs of the customer, the Net Metering rules require the utility to credit that excess energy back to the customer to offset that customer's future consumption. In Arizona, the excess energy is either credited in the same month the energy is created, or is carried over to a subsequent month. More importantly, this arrangement requires the utility to credit the net metering customer at the utility's full retail rate for any excess energy generated, even though the utility can purchase any needed energy on the wholesale market for a significantly lower price.

The combination of these regulatory policies results in the distributed energy customer receiving electric services that they need and require at no cost, while the responsibility for those costs is shifted to non-distributed energy customers.

Q. PLEASE PROVIDE AN EXAMPLE OF THE EFFECT OF THIS COST SHIFT ON NON-DISTRIBUTED ENERGY CUSTOMERS.

A. As an illustrative and very basic example of the nature of the cost shifting created by the net metering customer, imagine a utility system that serves 100 identical customers. Assume that the wires and other infrastructure used by this hypothetical utility system to serve its customers has an overall cost of $10,000. Under cost-of-service regulation, this $10,000 would be recovered equally from the 100 identical customers at $100 per customer.

If 50 of these customers installed rooftop solar generation under a Net Metering policy like the one in effect in Arizona today, they would no longer pay the $100 cost of infrastructure the utility uses to serve them. However, these Net Metering customers are still using, and the utility must still maintain, the same infrastructure because rooftop solar generation doesn't eliminate or displace any of these fixed costs. Under cost-of-service regulation, the utility still has $10,000 in costs that it needs to recover, but now only has 50 customers over which it can spread those costs. As a result, the remaining 50 customers' rates will rise to $200. In other words, 50 customers would pay nothing while 50 customers would see their bills double. Although this is an extreme example, the point is that the underlying Net Metering policy is inequitable and unsustainable, and is getting worse as more customers install rooftop solar.

Mr. Miessner provides a more detailed description of the impacts of distributed energy on non-participating customers in his direct testimony.

Q. WHAT IS THE MAGNITUDE OF THE COST SHIFT?

A. Each residential solar rooftop system installed in the Company's service territory that takes advantage of Net Metering creates an annual cost shift of approximately $1,000 to customers without distributed energy systems. The derivation of this calculation is described in Mr. Miessner's direct testimony.

Q. WHY DOES APS BELIEVE NET METERING POLICY NEEDS TO CHANGE NOW?

A. Since the Commission's Net Metering rules became effective in May of 2009, customer adoption of distributed energy resources, particularly rooftop solar installations, has skyrocketed.

There are currently over 18,000 solar rooftop systems installed in the Company's service territory today. Through May, APS had received as many as 500 new requests for interconnection of distributed renewable energy systems per month in 2013, even though direct cash incentives offered by the Company are minimal. This continued pace, despite minimal direct cash incentives, suggests the substantial role played by Net Metering.

Today, using the $1,000 annual cost shift I mentioned above, approximately $18 million has already been shifted to non-solar customers. Based on the number of requests for installation the Company is receiving today, this cost shift has the potential to grow quickly.

Q. IS APS THE ONLY UTILITY FACED WITH UNSUSTAINABLE NET METERING POLICIES?

A. No. This issue is being discussed throughout the nation. As highlighted in the December 17, 2012 Bloomberg article entitled "California Utilities Say Solar Raises Costs for Non-Users", California's Net Metering policy is expected to cause a cost shift to non-distributed energy customers of $1.3 billion annually. The California Public Utilities Commission is undertaking the same type of analysis of Net Metering that APS just completed—updating a previous study on the costs and benefits of the Net Metering policy on all customers. Other utilities and jurisdictions are currently exploring changes to lessen or eliminate the cost shifting inherent in Net Metering policies.

V. APS'S PROPOSED SOLUTIONS

Q. PLEASE BRIEFLY DESCRIBE APS'S PROPOSAL.

A. APS is proposing two separate solutions to the cost shift caused by current Net Metering policy, both of which are limited to residential customers. Each of these solutions will recover a more equitable portion of infrastructure costs from residential distributed energy customers, provide accurate price signals to both solar and non-solar customers, and would allow the Commission to provide more transparent incentives to distributed energy customers.

The first option proposed by APS is called the Net Metering Option. This option would retain the current net metering construct, but would require new residential solar adopters to take service under the Company's existing Rate Schedule ECT-2, which is a demand-based time-of-use rate schedule. Because this rate recovers more fixed infrastructure cost through a charge based on demand (kW) rather than a kWh charge, solar residential customers would pay their fair share of infrastructure costs, rather than shifting those costs to non-solar residential customers.

The Company's second proposed option is called the Bill Credit Option. Under this option, residential distributed energy customers would receive a bill credit for the entire output of their rooftop system at a market-based price. Residential customers could choose to take service from APS under any rate schedule for which they would otherwise be eligible. The bill credit would offset a customer's bill under whatever rate the customer has chosen. The Bill Credit Option would provide accurate price signals to solar customers and eliminate any cost shifting currently caused by Net Metering.

Each of these options is discussed in detail in Mr. Miessner's direct testimony.

Q. HOW DID APS DEVELOP THESE PROPOSALS?

A. As described in Mr. Bernosky's direct testimony, APS held technical workshops to evaluate the costs and benefits of distributed energy and Net Metering, inviting interested parties to participate in multi-session discussions to assist the Company in developing solutions to the Net Metering cost shift for ultimate presentation to the Commission. During the workshops, different studies were presented, evaluated and discussed, and the participants explored several differing viewpoints.

APS considered a number of options that could solve the inherent issues in Net Metering policy. All options were developed with four main goals in mind: addressing the current inequitable cost shift between customers, supplying energy to customers at reasonable cost, driving toward transparent incentives, and creating an adaptable, long-term solution. No option fully addressed all of these goals, but the two that APS is proposing are reasonable and equitable for all customers.

Q. WILL THESE SOLUTIONS APPLY TO CURRENT DISTRIBUTED ENERGY CUSTOMERS?

A. No. The Company proposes that either solution be applied to prospective residential distributed energy customers only. As described in Mr. Bernosky's testimony, APS's proposal includes provisions under which all current distributed energy customers and those who submit appropriate documentation to APS by October 15, 2013 will be grandfathered under the terms and conditions of APS's current Net Metering policy (as set forth in Rate Schedule EPR-6).

Q. SHOULD DISTRIBUTED ENERGY PROGRAMS CONTINUE TO RECEIVE INCENTIVES IN SOME FORM?

A. Up-front cash incentives have been an important means, along with Net Metering, for facilitating the installation of distributed energy systems. Changing the Net Metering policy to reduce cost shifting to non-solar customers would impact the level of up-front cash incentives needed. The difference with up-front cash incentives and Net Metering is that the Commission and other stakeholders can clearly see the costs of this incentive, and discuss the benefits, and because incentive costs are recovered from the RES surcharge, the costs would be spread more equitably across all customers. As described by Mr. Bernosky, in connection with the adoption of either option, APS proposes the continued use of up-front cash incentives as a transparent means to continue supporting the installation of rooftop solar.

VI. CONCLUSION

Q. PLEASE CONCLUDE YOUR TESTIMONY.

A. It is clear that, in order for renewable distributed generation to remain a viable and sustainable option for APS customers over the long term, change must occur. The cost shift caused by today's Net Metering policies must be modified. APS representatives, renewable and solar stakeholders, Commission Staff, and other interested parties have debated the costs, benefits, and value of renewable distributed generation over the past few months in technical conferences, workshops, and other venues. Regardless of the costs, benefits, or value of distributed generation, the simple fact is that customers with Net Metering should be fairly compensated for generation they provide, but should also pay a fair amount for the infrastructure they rely on and the services they use. Because Net Metering customers today do not pay a fair amount for the services they use, they shift those avoided costs to customers who do not or cannot install distributed energy. This is not a sustainable environment in which renewable generation will flourish in the long term.

Either of the two options proposed by APS will address this cost shift issue fairly and equitably, without harming customers currently taking advantage of today's Net Metering policy, and can be implemented without delay. I encourage the Commission to adopt one of the Company's proposed options.

DECLARATION

I declare that I have personal knowledge of the foregoing testimony, and that the foregoing is true to the best of my knowledge under penalty of perjury.

Signed: Jeffrey B. Guldner

Date: July 12, 2013

EXHIBIT 2

TESTIMONY OF GREGORY L. BERNOSKY

On Behalf of Arizona Public Service Company

Docket No. E-01345A-13-xxxx

July 12, 2013

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TESTIMONY OF GREGORY L. BERNOSKY
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
Docket No. E-01345A-13-XXXX

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Greg Bernosky. I am Arizona Public Service Company's (APS or Company) Manager of Renewable Energy and my business address is 400 North 5th Street, Phoenix, Arizona, 85004.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I graduated from the University of Illinois in 1998. I began my employment with APS in 2007 and primarily focused my efforts on transmission line and facility siting, and led stakeholder studies evaluating solar-rich resource areas throughout Arizona. I began working in the renewable energy area in 2010 and became the Manager of the APS Renewable Energy Program in 2012.

Q. WHAT ARE YOUR RESPONSIBILITIES AT APS?

A. I am responsible for developing, seeking regulatory approval of, and administering APS's renewable energy program.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I provided testimony in the Track and Record proceeding in May and June of this year and I have been the Company spokesman for APS's Renewable Energy Standard (RES) Implementation Plans in workshops and in Open Meetings.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to examine the intersection of Net Metering policy and APS's successful distributed energy (DE) programs, and to discuss the outcome of the Technical Conference that APS conducted at the Commission's direction earlier this year regarding the costs and benefits of distributed renewable energy and Net Metering. I also discuss the results of a new study that examined the predicted future value of rooftop solar in APS's service territory; propose an approach for transitioning to APS's proposed net metering solutions that is equitable for customers already participating in APS's DE programs; and address the potential for paying direct cash incentives to new DE customers upon the adoption of APS's proposal in this proceeding.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The renewable energy policies that have been part of the Commission's RES Rules and the Net Metering Rules have provided significant financial incentives for customers who install rooftop solar systems. These incentives have been instrumental in promoting the growth of DE in APS's service territory. As a result of these policies and declines in the cost of solar over the last several years, APS has already reached compliance with the DE requirements found in the RES until at least 2016.

Although direct cash incentives for solar rooftops have declined sharply, customer adoption of residential DE continues to increase. The significant cost savings associated with current Net Metering policy is a primary source of the subsidy that is driving DE adoption. However, as indicated in Mr. Miessner's testimony, the financial benefits of Net Metering come with higher costs for non-solar customers, as the Net Metering policies have created a shift in costs from solar customers to non-solar customers. The fact of this cost shift prompted APS to seek Commission approval to conduct a Technical Conference to examine these issues.

The Technical Conference was held in the first half of 2013, and included a broad range of participants, including representatives from solar industry organizations, solar installers and developers, regulatory interests, academia and utilities, among others. The purpose of the Technical Conference was to convene stakeholders to evaluate DE and Net Metering and gain a better understanding of the benefits from DE solar and the costs associated with current Net Metering policy. As a part of these meetings, studies were presented and evaluated, and several differing viewpoints were considered. In developing its proposed solutions, APS took into consideration the several months of Technical Conference discussions.

To recognize customers who have already installed DE, APS is proposing that a Commission-approved solution would only apply prospectively. This "grandfathering" concept would also be extended to those customers who (i) submit to APS an interconnection application and a signed contract with a solar installer by October 15, 2013; and (ii) interconnect their system within 180 days of APS receiving these materials.

Additionally, APS recognizes that the adoption of one of the proposed solutions may impact customer participation in DE. APS supports the use of direct cash incentives to encourage additional DE penetration. If that is the case, APS believes that 1) any direct cash incentives should be in the form of upfront incentives, and 2) that there should be flexible mechanisms to modify the incentive levels to change with market conditions.

III. APS'S DE PROGRAMS

Q. PLEASE DESCRIBE APS'S DE PROGRAMS.

A. Since APS filed its first RES Implementation Plan in 2007, APS has developed and implemented a wide variety of both residential and commercial DE programs. This has included a direct cash incentive program for residential customers, direct and production-based incentives for commercial projects, programs for schools, governments, and low-income customers, and a community pilot project in which APS is testing the performance of the distribution grid in an area of high DE penetration.

Q. WHAT KINDS OF SUBSIDIES ARE AVAILABLE FOR APS CUSTOMERS WHO INSTALL RENEWABLE ENERGY SYSTEMS?

A. Today there are four key subsidies available to APS customers who choose to install rooftop solar in Arizona: (1) federal tax incentives; (2) state tax incentives; (3) utility cash incentives; and (4) Net Metering.

Tax incentives – Residential customers may claim a federal Investment Tax Credit ("ITC") totaling 30% of the total cost of a solar electric generating system that is owned by the customer and installed on their residence. If a residential customer leases the system rather than owning it, the ITC accrues to the solar developer that owns the system. Today, approximately 80% of the residential solar installations in APS's service territory are installed under a lease option.

Residential customers may also claim an Arizona Solar Energy Credit, which is available to individuals who install a solar or wind generating system at their residence. This credit totals 25% of cost of the system, with a $1,000 maximum credit available. Arizona law contains other tax subsidies as well, such as sales tax exemptions for the sale of renewable energy and property tax exemptions for solar generating systems that are owned by the customer and produce energy for on-site consumption.

Direct Cash Incentives – APS DE programs offer two kinds of direct cash incentives: Up-front Incentives (UFIs) and Production-Based Incentives (PBIs). UFIs are lump sum cash payments paid to a DE customer at the time a system is installed. The amount of the UFI is based on the DE system's size (expressed in watts or kilowatts). PBIs, by contrast, are paid over time (typically 15 or 20 years) and are cash payments, the amount of which is based on actual system production. Since the inception of the RES Rules, APS has paid more than $180 million in UFIs to more than 26,000 rooftop solar and solar water heating residential customers, and has paid more than $60 million of a total PBI lifetime commitment of $772 million to 350 commercial customers who have installed DE systems.

Net Metering Incentives – Net Metering is a rate construct adopted by the Commission as a set of rules that became effective in May 2009. Under the Net Metering Rules, customers can install and take energy from their own generation. Using their own generation permits these customers to avoid paying for some or all of utility fixed costs that are embedded in energy usage charges. In addition, Net Metering permits solar customers to net excess energy produced by their DE system against the customer's future energy consumption, thereby expanding their ability to avoid charges for energy usage. The financial benefit of Net Metering stems from both the ability of Net Metering customers to self-supply energy and net excess generation against future consumption.

Q. HOW HAVE THE COMMISSION'S POLICIES IMPACTED THE GROWTH OF RENEWABLE ENERGY IN APS'S SERVICE TERRITORY?

A. The Commission's policies have been very successful at promoting the growth of renewable generation in APS's service territory. These policies include direct cash incentives and Net Metering, both of which have provided substantial financial advantages to customers installing DE. These financial advantages have led to a surge in DE installations over the last three years. In addition, reductions in the installed costs for DE and new financing options available to customers have contributed to the rapid expansion of DE. In 2012, APS received more applications for residential photovoltaic (PV) incentives than in 2010 and 2011 combined. APS saw only about 300 installations per month as recently as 2011. Now, more than 300MW of distributed generation has been installed in APS's service territory and approximately 500 new rooftop systems have been installed each month so far in 2013.

This upward trend has occurred during the same time period that direct cash incentives have declined steeply. Direct cash incentives for solar rooftop systems have plummeted from $3.00 per watt in mid-2010 to 10 cents per watt today.

With utility cash incentives approaching zero, many installers now identify the significant cost savings associated with current Net Metering policy as a primary source of the financial benefit provided by DE. But as described in the testimony of Mr. Charles Miessner, this financial benefit comes at a cost; the incentives found in the Net Metering rules shift costs from one customer group (DE customers) to another (non-DE customers).

Q. IS APS MEETING THE STATE'S DE REQUIREMENTS?

A. Yes. The unprecedented customer participation in DE has resulted in APS already reaching compliance with the DE component of the RES for future years. By the end of 2012, APS's total residential DE was 131% of the RES requirement and non-residential DE was 206% of the RES requirement. Based on the number of currently installed and reserved residential DE systems, APS expects to meet its residential DE compliance obligations through 2016 and its non-residential DE obligations through 2020.

IV. <u>EVALUATING IMPACTS OF NET METERING</u>

Q. HOW HAS APS EVALUATED THE POTENTIAL LONG-TERM IMPACTS OF NET METERING?

A. In November 2012, APS commissioned Navigant Consulting to (i) evaluate customer rates; (ii) determine what costs are shifted from solar customers to non-solar customers due to Net Metering; and (iii) analyze the magnitude of this cost-shift (the Navigant Study). The Company filed the Navigant Study on December 6, 2012 in Docket No. E-01345A-12-0290. This study's conclusions underscored the need to address the cost shift and supported APS's proposed Technical Conference described below.

Q. WHY DID THE ISSUES OF THE COSTS AND BENEFITS OF DE AND NET METERING NEED TO BE ADDRESSED AT THIS POINT IN TIME?

A. The magnitude of the cost shifting issue is already large and is expected to grow significantly over time. The cost shift is already approximately $18 million, and this amount is expected to grow by an additional $6 to 10 million per year. Non-solar customers will continue to pay for these shifted costs in the form of higher rates. Because the compounding effect of these shifted costs cannot be sustained in the long term, APS believes that action is needed now to implement a solution that is fair for all customers.

Q. WHAT STEPS DID APS TAKE TO ADDRESS THE COST-SHIFTING DILEMMA?

A. APS proposed a multi-series Technical Conference with stakeholders and other interested parties to evaluate the costs and benefits of Net Metering and DE. After collaborating with interested parties and stakeholders, APS committed to filing an application with proposed solutions to address the impact of DE on APS and its customers and to seek a solution that fairly balanced the costs and benefits of DE and Net Metering. The Commission supported this approach and in Decision No. 73636 ordered APS to conduct the proposed Technical Conference.

Q. WERE YOU INVOLVED IN THE TECHNICAL CONFERENCE HELD BY APS DURING THE FIRST HALF OF 2013?

A. Yes. As APS's Manager of Renewable Energy, it is my responsibility to develop and implement APS's renewable programs, and stakeholder involvement is a significant factor in those programs. I played a central role in organizing the Technical Conference, which initially included identifying a third-party facilitator to manage the process. Additionally, I worked with the facilitator to prepare the overall timeline and scope of the Technical Conference and generally supported the facilitator and APS team throughout the process. At the opening session, I introduced APS's position related to rooftop solar and the need to address issues related to the costs and benefits of DE and Net Metering.

Q. CAN YOU GENERALLY DESCRIBE THE PARTIES THAT PARTICIPATED IN THE CONFERENCE?

A. Participants included representatives from national solar policy organizations, members of the local solar policy and industry organizations, local installers and developers, academia, electricity consumer groups, governmental and regulatory interests, and other electric utilities.

Q. WHAT WAS THE PURPOSE OF THE TECHNICAL CONFERENCE?

A. The purpose of the Technical Conference was to convene stakeholders and evaluate the costs and benefits of distributed renewable energy and Net Metering, which included developing a better understanding of who benefits from, and who bears the costs of, these programs.

Q. HOW WAS THAT PURPOSE ACCOMPLISHED?

A. Content experts were enlisted to enhance the Technical Conference discussion through reports and presentations. Studies were conducted and presented by stakeholders and APS to evaluate the costs and benefits of DE and Net Metering.

As part of the discussions, APS retained the consulting firm SAIC Energy, Environment, and Infrastructure LLC to update the 2009 *Distributed Renewable Energy Operating Impacts and Valuation Study* (the Beck Study) that had been conducted by the RW Beck consulting firm. Because SAIC had acquired RW Beck, SAIC was uniquely situated to refresh the Beck Study. The SAIC *2013 Updated Solar PV Value Report* (the SAIC Study) was filed on May 17, 2013 in Docket No. E-01345A-12-0290.

Q. CAN YOU DESCRIBE THE PURPOSE AND THE RESULTS OF THE 2009 RW BECK STUDY?

A. The Beck Study was the first of its kind in Arizona. It involved more than 60 individuals representing 35 solar vendors, academic institutions, solar advocates, local builders and land developers, and solar-related construction firms, as well as representatives from the regulatory community. With input from this broad spectrum of stakeholders, the Beck Study developed methodologies and processes for determining the value of distributed solar energy to the utility. This methodology primarily used the cost of avoided fuel to establish the incremental financial value to the utility and its customers from DE over a multi-year period.

However, circumstances have changed significantly since 2009 when the Beck Study was completed. These changes include a steep decline in the price of natural gas and the accumulation of practical experience regarding the operational impact of significant DE penetration that was unavailable for the Beck Study. In light of these changes and informed by this tangible experience, the SAIC Study updated the Beck Study's predictions on the future value of distributed solar photovoltaic systems in the APS service territory installed after 2012.

Q. WHAT DID THE SAIC STUDY CONCLUDE?

A. The SAIC Study concluded that the primary source of cost savings to APS and its customers from rooftop solar PV remains energy-related costs, that energy produced from rooftop solar permits APS to avoid. These costs are variable and include the following:

- Fuel (primarily avoided natural gas purchases);
- Purchased power (avoided capacity or demand costs);
- Variable operations and maintenance costs (reduction in costs resulting from a need for lower amounts of generation);
- Emission related costs for thermal power plants (such as costs related to CO_2 emissions); and
- Avoided transmission and distribution losses (essentially "extra" energy that would have been needed from a centralized facility to replace the energy lost during delivery from the plant to the customer).

Q. DOES APS BELIEVE THAT THE SAIC STUDY OFFERS A REASONABLE PREDICTION REGARDING THE BENEFIT OF DE?

A. Yes. The Beck Study concluded and the SAIC Study confirmed that natural gas prices are the primary driver behind the energy-related costs that form the bulk of the savings that flow from DE. The Beck Study reflected a value-based upon high natural gas costs in 2009, whereas the SAIC Study reflected a new natural gas cost that is low now and is projected to remain low. With this updated data informing Beck's verified methodology, the SAIC study represents a reasonable prediction of the benefit that rooftop solar provides to APS and its customers.

Q. HOW DID THE SAIC STUDY IMPACT APS'S PROPOSED SOLUTIONS?

A. The SAIC Study provided important information, but was not the primary basis of APS's proposed solutions, as discussed in detail in Mr. Miessner's testimony.

Q. WHAT WAS THE OUTCOME OF THE TECHNICAL CONFERENCE?

A. APS and stakeholders concurred that DE provides benefits in the form of avoided fuel costs and some amount of deferred or avoided infrastructure investment, although there was disagreement on the amount and type of infrastructure that DE defers. There was no clear consensus on how DE and Net Metering should be evaluated when developing utility programs, and specifically, what costs and benefits should be included when performing such evaluations.

Q. HOW DID APS INCORPORATE DISCUSSIONS DURING THE TECHNICAL CONFERENCE IN ITS PROPOSED SOLUTIONS?

A. APS developed its proposed solutions taking into consideration the several months of discussion between renewable energy stakeholders, APS, and other interested parties regarding the costs, benefits, and value of distributed generating systems. APS used this information when assessing the varied, possible solutions to the cost shifting dilemma as described in the testimony of Mr. Charles Miessner.

V. <u>INCENTIVES AND GRANDFATHERING UNDER APS'S PROPOSED DISTRIBUTED ENERGY SOLUTION</u>

Q. DOES APS INTEND TO APPLY THE OPTIONS DESCRIBED IN MR. MIESSNER'S TESTIMONY TO CUSTOMERS WHO HAVE ALREADY INSTALLED SOLAR ON THEIR HOMES?

A. No, APS proposes that any Commission-approved solution would only apply prospectively. DE customers that are currently under APS's current Net Metering program would be grandfathered for a maximum of 20 years under the terms and conditions of that program. The grandfathering would not be transferable to a new customer at the same premise.

Q. **WHAT HAPPENS TO CUSTOMERS WHO ARE IN APS'S QUEUE AND WILL SOON INSTALL NEW ROOFTOP SOLAR UNDER APS'S PROPOSAL?**

A. Customers who submit to APS an executed interconnection application and a signed contract with a solar installer by October 15, 2013, and complete the installation of their solar system within 180 days of that submission, would be grandfathered under the existing program.

Q. **DOES APS ANTICIPATE THAT IT WILL BE ABLE TO MEET ITS RES DE COMPLIANCE REQUIREMENTS UNDER EITHER OF THE PROPOSED SOLUTIONS?**

A. APS has already reached its residential DE requirement through 2016. Therefore, if either proposal slows the installation of residential DE, APS's ability to comply with the RES Rules will not be immediately jeopardized. Under APS's proposal, either option would be effective on January 1, 2014—a full two years before APS must acquire additional DE.

Q. **ARE FINANCIAL INCENTIVES NEEDED FOR EITHER OF THE PROPOSED OPTIONS?**

A. Because updating the current Net Metering programs may impact customer participation, APS supports the use of further financial incentives, which would make incentives more transparent.

Q. **DOES APS HAVE RECOMMENDATIONS AS TO HOW FINANCIAL INCENTIVES SHOULD BE STRUCTURED FOR ITS PROPOSED OPTIONS?**

A. If the Commission decides that financial incentives should be addressed at this time, APS proposes the following parameters to assure a transparent and sustainable incentive structure.

First, all residential DE incentives should be in the form of UFIs. As described above, UFIs are a one-time cash payment based on the system's designed size. This is a transparent, flexible means to incentivize installations that can be finely tuned in response to changes in market conditions.

Second, the process for modifying incentive levels should be flexible, allowing for changes in incentive levels as necessary to reflect changing market conditions. Incentive modifications should be made more frequently than they are currently in order to timely calibrate the desired level of DE adoption to the amount of incentives required to cause that level of adoption. These parameters would grant the Commission more control over the level, and more visibility into the quantity and effect, of incentives. Incentive adjustments could occur through various means, including automatic adjustments through an existing structure or by a third party administrator that assumes control over incentive program management.

VI. <u>CONCLUSION</u>

Q. DO YOU HAVE ANY CONCLUDING COMMENTS?

A. In considering APS's proposals, APS requests that the Commission also consider our proposal for grandfathering current residential DE customers and those customers who submit interconnection applications and agreements by October 15, 2013 and install their rooftop units on their homes within 180 days. And should the Commission agree with APS's support of paying direct cash incentives to assure adequate customer participation in DE under either of the proposed options, APS recommends that direct cash incentives be in the form of upfront incentives only, and that a flexible process for modifying the incentives be adopted.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Declaration

I declare that I have personal knowledge of the foregoing testimony and that the foregoing is true to the best of my knowledge under the penalty of perjury.

Signed:____________________
Gregory L. Bernosky

Date: 7/12/13

EXHIBIT 3

TESTIMONY OF CHARLES A. MIESSNER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-13-xxxx

July 12, 2013

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**TESTIMONY OF CHARLES A. MIESSNER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
Docket No. E-01345A-13-XXXX**

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Charles A. Miessner, 400 North Fifth Street, Phoenix, Arizona 85004.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Pricing Manager for Arizona Public Service Company (APS or Company).

Q. WHAT ARE YOUR PROFESSIONAL QUALIFICATIONS?

A. My qualifications are provided in Attachment CAM-1, Statement of Qualifications.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to support APS's proposed options to modify rooftop solar and Net Metering policy; describe the current Net Metering program and explain how it shifts costs to non-solar customers and increases rates; discuss some of the research, evaluations, and information that the Company relied on to develop its proposals, including information from the recent Technical Conference on the costs and benefits of rooftop solar; and provide the potential impacts of APS's proposals to customers that are participating in solar programs and to those that are not.

III. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. In my Direct Testimony, I provide an overview of the current Net Metering program and explain how it shifts costs from customers with solar to those without solar, and by doing so, raises overall rates; I describe how Net Metering causes the cost shift because solar customers do not pay their fair share for infrastructure they rely on and services they use; and I emphasize that concern over the cost shift is about customer fairness and the rate increases that the cost shift will cause.

I also detail the causes and the size of the cost shift; I show that the cost shifting exists under current rates and the underlying embedded costs, as well as for the marginal or growth in costs over time; I review the accuracy of certain perspectives raised during APS's 2013 Distributed Energy Technical Conference; I outline the Company's proposed options for addressing the cost shift and emphasize that the options do not increase rates beyond the most recent rate case; and I discuss bill impacts under APS's proposed options.

IV. REQUESTED CHANGE TO THE NET METERING PROGRAM

Q. WHAT IS APS'S PROPOSAL REGARDING CURRENT NET METERING POLICY?

A. APS proposes two options—the Net Metering Option and the Bill Credit Option—for modifying current Net Metering policy in order to address how costs are being shifted to, and increase the rates of, customers without solar. These options will require new residential solar customers to either (1) be billed under Rate ECT-2, which is an existing time-of-use rate with a demand charge, or (2) be credited for their entire solar output at a market-based price. The current Net Metering billing arrangement, Rate Rider Schedule EPR-6, will continue to be available with Rate ECT-2; Net Metering would be moot under the Bill Credit Option. For reasons related to incentives, among others, the Net Metering Option and the Bill Credit Option are mutually exclusive.

Furthermore, APS proposes that the requested modifications only apply to new residential solar customers, as described below. Existing and immediately pending residential customers with rooftop solar will continue to be served under the existing Net Metering program and retail rates. Because APS's proposal is only directed at residential customers, all business customers with solar will be similarly unaffected.

Q. WHY IS APS REQUESTING THIS CHANGE?

A. APS believes that the current Net Metering program is not sustainable because it (i) unfairly shifts costs to customers that are not participating in the program; and (ii) will eventually result in higher rates for non-solar customers.

Q. PLEASE EXPLAIN.

A. Under the current Net Metering program solar customers do not pay their fair share for infrastructure they rely on and services they use. These costs are ultimately shifted to (and thus increase the rates of) customers without solar. In other words, a significant portion of the bill that customers avoid by installing solar gets paid by non-solar customers.

V. <u>CURRENT NET METERING PROGRAM</u>

Q. PLEASE DESCRIBE APS'S CURRENT NET METERING PROGRAM.

A. APS currently offers Net Metering to residential and business customers that install a solar generator, or other renewable fuel types, on their premises. Under the program, customers with their own renewable generation may interconnect to the system and self-provide some of their own generation needs. Despite having rooftop solar, these customers still rely on and receive service from the electric grid. The services a solar customer still receives include (i) the generation and delivery of any energy shortfall when the rooftop system doesn't produce enough energy to meet 100% of the customer's requirements; (ii) a connection to a grid onto which the solar customer can export power when their rooftop solar system is producing more energy than the customer needs; (iii) the provision of power quality and stability services (e.g., voltage and VAR support that are needed for the rooftop unit to function properly); and (iv) the provision of backup power so that when the rooftop solar system suddenly stops producing, such as when clouds pass overhead, the customer's electricity use continues without even a momentary outage.

In addition to self-supply, Net Metering allows solar customers to net power generated in excess of the customer's needs against future energy usage on their bill. This excess power can be carried forward and netted against usage in a subsequent month. At the end of the year, APS purchases any remaining carry forward energy at an avoided cost rate.

Q. HOW MUCH ENERGY PRODUCED BY A SOLAR SYSTEM IS USED FOR SELF-SUPPLY, AND HOW MUCH BECOMES EXCESS ENERGY?

A. On average for a residential Net Metering customer, roughly 80% of the solar generation immediately serves their household load and the remaining 20% is excess generation. The year-end purchase is typically 5% of the total solar generation, but varies according to the amount of solar the customer installs and their retail rate schedule.

Q. CAN CUSTOMERS CHOOSE A RATE PLAN UNDER NET METERING?

A. Yes. The Net Metering program is a billing arrangement that can be used in conjunction with a variety of retail rates, including, for residential customers, the standard inclining block rate, the time-of-use rates and the time-of-use rates with demand charges. The "netting value" of the excess generation, as well as the charges for the grid and other services provided by APS, are all according to the customer's retail rate.

Q. ARE THERE ANY LIMITS TO THE PROGRAM?

A. Very few. The program is governed by Net Metering rules established by the Arizona Corporation Commission. Under the rules, the only practical limit is that the capacity of the customer's solar unit cannot be larger than 125% of their connected load, which is the maximum potential electrical usage for their home at any point in time. Beyond that, Arizona's Net Metering rules involve none of the limitations that other states might have.

Q. PLEASE ELABORATE.

A. Most of the 47 states that permit Net Metering impose one or more limitations on participation. These limitations can include caps on (i) the size of individual rooftop solar units; (ii) the total rooftop solar capacity that can be installed on a system; and (iii) the total funding available for Net Metering. Arizona's Net Metering rule does not include any of these limitations.

Q. WHAT IS THE CURRENT PARTICIPATION IN APS'S NET METERING PROGRAM?

A. Currently there are approximately 18,000 rooftop solar systems installed on APS's system. Over 95% of these units are for residential customers participating in the Net Metering program. Most of the other 5% are for business customers who also participate in Net Metering. A small number of customers participate in a Net Billing program, rather than the Net Metering. Attachment CAM-2 provides information on the number of customers with rooftop solar by major rate group.

Q. PLEASE DESCRIBE THE NET BILLING PROGRAM.

A. APS offers two Net Billing programs for solar customers (and other qualifying generators). Under Net Billing, APS purchases a solar system's excess generation each month at an avoided cost rate, instead of that excess being netted against kWh usage on a current or subsequent bill.

Q. WHAT IS THE PARTICIPATION IN THOSE PROGRAMS?

A. Currently there are approximately 107 customers with rooftop solar participating in one of the Net Billing programs.

Q. DO THE ISSUES AND PROPOSALS IN THIS MATTER ALSO APPLY TO NET BILLING CUSTOMERS?

A. Yes. The issues and proposals apply to all rooftop solar customers, regardless of their particular billing arrangement. Net Metering shifts more costs than Net Billing because Net Metering applies to the 20% excess solar generation discussed above, as well as the 80% of solar generation that directly serves the customer's load. By contrast, only the 80% of solar generation that directly serves load shifts costs to other customers under Net Billing. The excess generation (the remaining 20%) does not shift costs to other customer's because the monthly purchase rate is based on the short term avoided cost of generation.

Because the Net Billing program involves less than 1% of the rooftop solar systems in APS's service territory, I emphasize Net Metering in my testimony, even though the cost shift issue and proposals apply to both programs.

Q. WHY MIGHT CUSTOMER ENROLL IN THESE PROGRAMS?

A. Customers participating in Net Metering typically receive five benefits. The first, and by far largest, benefit is the bill savings resulting from solar generation that immediately serves household load. The second benefit is the bill savings from the netting of excess generation on the monthly bill. The third benefit is the bill savings from the ability to carry-over excess generation to a future bill. The fourth benefit is the bill credit from the sale of remaining excess generation at the end of the year. And the fifth benefit is that the customer pays no stand-by generation charges in case their generator fails, which are typical for customers with other types of on-site generators.

Participants in the Net Billing program enjoy the first and fourth benefit. Net Billing customers with smaller generators also receive the fifth benefit as well.

Q. HOW ARE THE BILL SAVINGS FOR NET METERING DETERMINED?

A. It depends on the type of rate under which the customer takes service. For example, the residential inclining block rate has two types of charges: a kilowatt hour (kWh) charge which is applied to the total energy consumption for the month, and a basic service charge, which is a flat amount per month regardless of usage. For a typical customer, kWh charges comprise about 91% of the bill and the basic service charge makes up the remaining 9%. By self-supplying through Net Metering, a solar customer saves on all of the kWh charges to the extent the solar system reduces energy consumption from the utility; self-supply does not, however, reduce the basic service charge.

Like self-supply, excess generation reduces kWh charges. If a customer's solar generation is higher than their load in any hour, the resulting excess generation is exported to the grid and netted against the current monthly bill, or if necessary, a future bill. This netted amount applies to all of the kWh charges on the bill, but does not apply to the basic service charge. In this regard, the solar customer receives the full retail value of kWh charges for both the solar generation that is immediately consumed and the amount that is exported to the grid and ultimately netted on the bill. The customer also saves on the taxes and other governmental fees, such as franchise fees and regulatory assessment fees, which are passed through to state and local governments. For a typical customer, these taxes and fees add about 9.5% to the bill.

Q. HOW DOES NET METERING AFFECT BILLS THAT INCLUDE DEMAND CHARGES?

A. Some rate schedules have demand charges in addition to the kWh charges and basic service charge. For residential customers, the demand charge is applied to the highest hourly usage during the billing month. Under rates with demand charges, solar generation still results in savings on all of the kWh charges through the self-supply and netting of excess generation, but would have a lower savings on the demand charge. This is because the solar generation does not reduce load equally in every hour of the month, such as in the early mornings, evenings, and nighttime, or in the day time when clouds interrupt the solar generation or the solar inverter is cycling off. In fact, the peak load for many residential homes occurs between 6:00 to 8:00 p.m., a time when the family is at home and the air conditioner load is still high, but solar generation is dwindling as the sun sets. If a residential solar customer's peak usage occurs during this time period, the solar system may reduce only a small portion of their demand, if any.

Examples of monthly bill savings for solar customers on the inclining block kWh rate and a demand charge rate are provided in Attachment CAM-3. Although actual customer experience can vary due to the size of the customer, load shape, and the amount of solar they install, the examples provided are typical for many customers.

Q. HOW MANY RESIDENTIAL CUSTOMERS ARE ENROLLED IN A RATE WITH A DEMAND CHARGE?

A. For residential customers, about 10%, or approximately 100,000 customers, are served under a rate that includes demand charges.

VI. THE COST SHIFTING ISSUE

Q. WHAT IS THE PROBLEM WITH THE CURRENT NET METERING PROGRAM?

A. The current Net Metering program is not sustainable because it unfairly shifts costs to customers that are not participating in the program. This cost shifting occurs because solar customers do not pay their fair share for infrastructure they rely on and other services they receive. The end result is higher rates for non-solar customers. This issue is exacerbated by the netting of excess generation.

Q. PLEASE ELABORATE.

The electricity that APS provides can generally be thought of as a bundle of individual services that are necessary to serve a home or business. Many of these services are line-itemed as specific unbundled components on the monthly bill. These generally include power plants, fuel, transmission, distribution, metering and billing, public policy programs, and taxes and other government fees. A high level description of each of these services is provided below in Table 1 along with the current average residential rate per kWh.

As shown, the average rate for residential customers is currently about 12.6 cents per kWh before taxes and government fees, and 13.8 cents per kWh after taxes. This reflects the billed amounts for calendar year 2012 before taxes, the current rate adjustment for fuel costs, and an average composite tax rate of 9.5%. It includes all residential customers—small, medium, and large, renters and homeowners, and those receiving low income discounts, the latter comprising about 7% of the total customers.

However, the typical rate for a solar customer is 13 to 16 cents per kWh with taxes (prior to adding solar)—because solar customers typical have higher than average energy usage and do not receive low income discounts, among other differences.

Table 1. APS's Services and Average Residential Rate (Cents per kWh)

SERVICE	DESCRIPTION	Rate
Power Plants	The infrastructure costs for generating electricity	2.8
Fuel and variable O&M	The variable costs of operating the power plants	4.0
Transmission	The infrastructure costs of the extra high voltage wires and system	1.1
Distribution	The infrastructure cost for local substations and wires	2.7
Metering and Billing	The fixed cost for metering and billing customer's usage	1.1
Public Benefit Programs	Funding for low income discounts, nuclear decommissioning, solar programs, energy efficiency programs, and other public benefit expenditures	0.9
Subtotal	Before Taxes and Gov't Fees	12.6
Taxes and Gov't Fees	Pass through costs to state and local governments.	1.2
Total	Average customer	13.8
Total	**Typical solar customer**	**13.0 -16.0**

Q. **PLEASE DESCRIBE THE INFRASTRUCTURE AND FIXED BUDGET COMPONENTS OF THE BILL.**

A. The power plant costs recover the capital costs of APS's generation fleet, including its nuclear, coal, gas, solar, and other power plants. The transmission costs include the high voltage lines that deliver energy from the power plants to the city or load centers, and other related equipment such as transmission level substations. The distribution costs generally concern the local grid (as opposed to long distance transmission lines), and reflect the costs associated with distribution lines, substations, transformers, and service connections to homes and businesses. The metering and billing costs include the capital costs for the AMI metering system and other alternative metering equipment, as well as the cost to compute and render the monthly bill. The public benefit programs include funding for low income discounts, solar programs, energy efficiency programs, and other public policy programs directed by the Arizona Corporation Commission. Although the public benefit programs are not typically capital or infrastructure costs, they have fixed annual budgets or funding requirements.

Q. HOW MUCH OF APS'S TOTAL COSTS ARE COMPRISED BY INFRASTRUCTURE AND FIXED BUDGET COSTS?

A. The infrastructure costs are approximately 61% of APS's total costs. The public benefits programs comprise another 7%.

Q. HOW SHOULD THESE INFRASTRUCTURE COSTS BE RECOVERED?

A. These infrastructure and fixed-budget costs should be recovered fairly from each customer that takes service from APS. Ideally, these costs should be recovered through either a demand charge, a basic service charge, or other alternative to a kWh charge because the costs are not driven or determined by the customer's monthly energy consumption. For example, the costs associated with the grid infrastructure are still incurred, even if a customer reduces their kWh usage for portions of a day or month.

Q. HOW ARE INFRASTRUCTURE COSTS RECOVERED FROM RESIDENTIAL CUSTOMERS IN CURRENT RATES?

A. APS assessed the cost and charge types for the various unbundled services on the bill for each of our major residential and business rates. A depiction of the findings is provided in Attachment CAM-4. This assessment demonstrates that the recovery of infrastructure and fixed budget costs is misaligned with the rate structure for approximately 90% of residential customers. These costs are recovered through variable usage charges, but are not variable costs. The basic service charge is a fixed charge, but it only recovers the metering and billing costs. And as mentioned above, only about 10% of residential customers are served by rates with demand charges. Thus, the vast majority of fixed costs are recovered through variable kWh charges from residential customers.

Q. WHAT ARE THE CONSEQUENCES OF THIS MISALIGNMENT?

A. In the absence of Net Metering, the consequences are generally not serious. Typically, customers that do not generate their own power and receive generation service from APS for their entire load continue to pay their fair share of infrastructure costs. This is because they are not substantially avoiding or reducing the kWh consumption upon which the charges are based. Although recovering fixed costs from non-solar customers through a demand charge or basic service charge would better align fixed charges with fixed costs, customers without solar still fairly contribute to the costs necessary to serve them under existing rates.

For Net Metering customers, however, this misalignment shifts infrastructure and fixed budget costs to customers without solar, raising their rates. This occurs because solar customers still use the electrical infrastructure, but avoid paying for the costs necessary to support that infrastructure, by avoiding variable energy charges.

Q. WHAT SERVICES DO SOLAR CUSTOMERS PROVIDE THEMSELVES?

A. Referring back to the various unbundled utility services summarized in Table 1, residential solar customers only provide themselves the fuel and variable O&M service and a portion of the power plant service. To the extent that rooftop solar generates power, it displaces the need for APS to buy fuel. For every kWh of solar generation, APS avoids a kWh of fuel costs. In addition, rooftop solar displaces some, but not all, of APS's power plant costs (also known as capacity costs). Although rooftop solar can, at times, function like, and provide services similar to, a miniature power plant, rooftop solar cannot replace APS's power plants. Rooftop solar customers still need APS power plants to serve their nighttime (and a portion of their daytime) load, and to be on call at all times to provide backup generation in case the solar generator stops producing power.

The exact amount of power plant costs that rooftop solar displaces is not precisely known, but a reasonable estimate is 50% of the rooftop solar system's capacity value based upon current conditions. Higher penetrations of rooftop solar in the future, however, would likely reduce this capacity value dramatically because APS's peak load would be shifted into the early evening hours where the solar generation would have a lower impact.[1]

In addition, because rooftop solar is available intermittently during the day and located at the customer's home, it could theoretically have a small impact on the cost of transmission service by delaying the investment in future infrastructure. This partial impact would depend on the timing and magnitude of total rooftop installations concomitant with APS's planned transmission upgrades. As a result, while such an impact is theoretically possible, APS's detailed assessment concludes that rooftop solar would have no near term impact on delaying actual planned transmission investments, and only a minimal impact in 2025.

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[1] For example, the 2013 SAIC study determined the incremental capacity value or rooftop solar in 2025 would be approximately 5% given projected increased solar adoption.

Q. DOES THE SALE OF EXCESS ENERGY PROVIDE ANY ADDITIONAL SERVICE?

A. No. The sale of excess energy only permits APS to avoid buying fuel or short-term power purchases. It does not provide any other of the services listed on Table 1, including power plant capacity, because the excess generation is not a reliable source of power.

Q. BASED ON THE RESIDENTIAL BILL IN TABLE 1, WHAT IS THE MONETARY VALUE OF THE SERVICES PROVIDED BY ROOFTOP SOLAR?

A. Based on the charges for the unbundled services, which represent the underlying costs to serve customers, the solar customer should save roughly 5.4 cents per kWh on their bill—4.0 cents for fuel and variable O&M costs and 1.4 cents per kWh for 50% of the power plant costs (50% times 2.8 cents per kWh). They would also typically save another 9.5% to reflect reduced taxes and government fees, which would bring the total savings to approximately 5.9 cents per kWh with taxes. These savings numbers are all based on the embedded or average cost of service that is reflected in rates.

Q. HOW MUCH DOES A SOLAR CUSTOMER CURRENTLY SAVE ON THEIR BILL?

A. It depends on their rate schedule, monthly consumption and the amount of solar that they install, but the typical solar customer saves approximately 15 cents per kWh with taxes (13.5 before taxes). Examples of customer bills with rooftop solar for various residential rates are provided in Attachment CAM-3. These examples are representative of many customers that are currently participating in Net Metering.

Q. WHAT ARE THE RESULTING COSTS THAT ARE SHIFTED TO CUSTOMERS WITHOUT SOLAR?

A. The precise amount of the cost shift varies for each solar customer depending on the factors discussed above. For the representative solar customer provided in Attachment CAM-3, the amount shifted to other customers is around 8.1 cents per kWh, which is the actual bill savings of 13.5 cents per kWh bill savings, less the 5.4 cents per kWh of utility cost savings for the fuel and power plant services discussed above. Taxes are excluded from these numbers because they are a pass through cost to APS and therefore do not result in utility costs that are shifted to other customers.

The cost shift is even higher if the bill savings are compared to the current "marginal" costs for fuel and power plant capacity.

Q. WHY IS THE COST SHIFT HIGHER USING MARGINAL COSTS?

A. Currently, the near-term marginal cost of fuel and power plant capacity, or cost of the last kWh of generation, is lower than the average cost. This is due to the current low cost of natural gas, which is the marginal fuel, and the relatively soft generation capacity markets in Arizona. The marginal cost for fuel and 50% power plant capacity over the next year is closer to 3.1 cents per kWh, rather than the 5.4 cent per kWh under average costs. Based on marginal costs, the cost shift to customers without solar in the near term is roughly 10.4 cents per kWh (13.5 cent bill savings less 3.1 cent marginal cost reductions). Of course, this amount would change over time as fuel and generation capacity costs change.

Q. WHAT IS THE OVERALL LEVEL OF COSTS SHIFTED FROM ROOFTOP SOLAR CUSTOMERS TO OTHERS?

A. We can only estimate this amount at this time because a precise amount would require rebilling all 18,000 solar customers and calculating their specific bill savings. However, in general terms, using the bill savings estimates for the representative residential customer, the annual costs shifted to other customers is approximately $800 using the average costs in rates and $1,000 using the short-term marginal costs. With 18,000 solar rooftop systems currently installed on APS's system, the total costs shifted to other customers are in the range of 15 to 20 million dollars per year.

Q. WHAT ROLE DOES THE NETTING OF EXCESS GENERATION PLAY IN THE COST SHIFT?

A. The netting of excess solar generation against the customer's bill exacerbates the cost shift because it provides full retail bill savings for the 20% (on average) excess solar generation that is exported to the grid. Thus, it extends the cost shifting issue to this portion of rooftop solar generation as well.

VII. <u>PERSPECTIVES OF ROOFTOP SOLAR COMPANIES ON COST SHIFTING</u>

Q. WHAT ARE THE PERSPECTIVES OF ROOFTOP SOLAR COMPANIES ON THE COST SHIFTING ISSUE?

A. Rooftop solar companies offered their viewpoints regarding rooftop solar and Net Metering in the recent technical workshops and elsewhere. They typically assert, among other things, that: (1) rooftop solar does not shift costs to other customers; (2) rooftop solar is similar to energy efficiency; and (3) if there is a cost shift, it's just one of many cost allocation issues in rates.

Q. DO YOU AGREE WITH THESE ASSERTIONS?

A. No. Although APS appreciated and learned from the frank and spirited discussions in the technical workshops, the Company does not believe that these conclusions are valid, factually correct or compelling from a policy perspective.

Q. PLEASE ELABORATE.

A. Concerning the claim that rooftop solar does not shift costs, rooftop solar companies typically claim that solar customers use less of the utility infrastructure, and that by using less, utilities don't need to make as many investments in the future. According to rooftop solar companies, this will result in long term cost reductions that justify solar customers not paying for any infrastructure costs today. This claim lacks merit. As discussed above, customers with solar rely on and use the grid and APS power plants twenty-four hours a day. This use includes, but is not limited to, (1) supplying the customer's electricity needs when their solar unit is not running—both at night and intermittently during the day; (2) supplying the customer's peak power requirements between 6 p.m. to 8 p.m., right when the solar system's production drops off significantly; (3) maintaining backup generation at all times so that if the rooftop solar system fails, a cloud passes over or the production drops off for other reasons, the customer can continue taking power without even a momentary interruption; and (4) providing the voltage and VAR support required for the rooftop solar unit to function properly.

To the extent that customers with solar use the grid, they should pay for that use. Although rooftop solar customers do self-provide their own fuel and a portion of their utility power plant services, their use of the grid still requires utilities to make substantial infrastructure investments in power plants, transmission lines and distribution equipment.

Q. ROOFTOP SOLAR COMPANIES CLAIM THAT ALTHOUGH SOLAR CUSTOMERS USE THE GRID TODAY, THEY WILL NONETHELESS ELIMINATE FUTURE COST SHIFTS THROUGH A REDUCED NEED FOR INVESTMENTS. DO YOU AGREE?

A. No. Based on current projections, the cost shifting problem will persist into future years if left unresolved. In its 2013 Distributed Energy Technical Conference, both APS and rooftop solar companies presented studies that assessed the potential impact of rooftop solar on cost shifting and rates. APS presented two studies. The first study was conducted by Navigant Consulting and assessed the cost shifting issue under current costs and rates. The second study was conducted by SAIC and developed a long-run evaluation of the benefits of rooftop solar in terms of saving future utility fuel and infrastructure costs. Rooftop solar companies presented a study by Cross Border Energy that assessed the long-run impact of rooftop solar on APS's costs and rates.

Q. WHAT WERE THE RESULTS?

A. The results are vastly different. The APS-sponsored studies reported utility marginal cost savings from rooftop solar for fuel and infrastructure that ranged from $0.034 per kWh today to $0.08 in 2025. These studies demonstrated that residential rooftop solar shifts costs to other customers both today and in the future. The Cross Border study, on the other hand, found that rooftop solar will save APS between $0.22 and $0.24 per kWh levelized over the next twenty years. Based on this range, Cross Border concluded that residential rooftop solar does not shift costs to other customers when assessed over a twenty year period.

Q. WHAT ARE YOUR COMMENTS ON THE ROOFTOP SOLAR COMPANIES' RESULTS?

A. APS strongly disagrees with the Cross Border results and conclusions. Without getting into too many technical details, the rooftop solar companies have provided a grossly inflated depiction of the benefits of rooftop solar in terms of the timing and magnitude of utility infrastructure cost savings, as well as other purported benefits. Additional benefits claimed from rooftop solar, such as long term fuel hedging, impacts on national and regional commodity prices, employment benefits from solar jobs and compliance costs for the renewable portfolio standard are either double counting, spurious, unproven or all three. These flaws are so fundamental in nature that APS believes the Cross Border study does not merit serious consideration.

Q. ARE THERE ANY WAYS TO PROVIDE A THRESHOLD REASONABLENESS CHECK FOR THE STUDY RESULTS?

A. Yes. I believe that there are a couple of ways to assess whether the Cross Border study results fall within a reasonable range. The first indication that the rooftop solar companies' estimates of utility cost savings from rooftop solar appear to be beyond the realm of reason is that they are roughly twice the current level of retail rates for residential customers. In other words, Cross Border concludes that the solar savings of rooftop solar will grow so much over the next 20 years that the levelized annual savings will be 200% of APS's total costs, costs that include all of APS's power plants, transmission lines, substations, distribution lines, meters, service trucks, operating buildings, computer systems, furniture and everything else. This result just does not seem plausible.

Second, as discussed below, APS could currently purchase solar energy for a twenty year period from large solar power plants (called utility scale solar), at a cost that is far below the value of rooftop solar cited in the Cross Border study. Importantly, this utility scale solar could be located at or near a load center, and thus provide most, if not all, of the rooftop solar benefits claimed by rooftop solar companies. Why should customers effectively pay a rooftop solar customer $0.24 per kWh when they could obtain the same benefits from utility scale solar for $0.08 to $0.09 cents per kWh? The answer is they shouldn't. This comparison further suggests that the Cross Border study results are beyond what any reasonable study could possibly conclude. Compensation for rooftop solar should never be higher (much less three times higher) than the price to purchase an equivalent, or near equivalent, alternative.

Q. DOES APS BASE ITS RATES AND BILLING POLICIES ON LONG RUN PROJECTED COST STUDIES?

A. No. APS performs rate impact studies and other long-range cost studies as part of our financial and rate planning. They are used for strategic planning and for setting direction and policy. However, they are not used to determine overall rate levels, rate design, or otherwise influence a customer's monthly bills. APS's rates are set to recover historic test year costs as determined by the Commission. Therefore, even if residential rooftop solar passes a long run rate impact test (which it doesn't), it isn't appropriate to design rates or otherwise justify that a customer not pay for utility services that they still receive based on this information.

Q. WHY NOT?

A. APS believes that a customer should pay for the services they are receiving from the utility. If, however, they can self-provide some of these services, then their bill savings should be based on the current prices for the services they self-provide, not a prediction of what those services might be worth over the next twenty years. To the extent that the services provided by rooftop solar actually do become more valuable over time, the bill savings will grow to reflect this increased value. But it is not appropriate or fair to base a higher level of compensation for rooftop solar today based on hypothetical marginal costs in the future. What happens if the events upon which the future savings are based never occur? In that case, non-solar customers would have been paying all along for a predicted benefit, only to have that benefit never materialize.

Q. DO ANY UTILITIES SET RATES OR BILLING POLICIES BASED ON THESE TYPES OF LONG-RUN MARGINAL COST STUDIES?

A. No. None at all to my knowledge. Some utilities have forward test years where rates are set to recover projected average costs one or two years in the future. Other utilities perform near term marginal cost studies as part of their rate analysis. However, even in these cases, the utility sets rates to recover near term average costs, not long term projected marginal costs.

Q. ROOFTOP SOLAR COMPANIES CLAIM THAT IF SOLAR IS A SUBSIDY IT'S JUST ONE OF MANY SUBSIDIES THAT OCCUR IN THE RATE MAKING PROCESS. DO YOU AGREE?

A. No. Not at all. Their assertion seems to be twofold—there are numerous subsidies built into current rates, and that because there are many subsidies, it's unfair to try to solve any of them. Neither assertion is valid.

There are a few subsidies built into rates, but only a few. For example, APS currently offers rate discounts for qualified low income customers. This discount is a rate subsidy that shifts costs between customers that participate in these programs and those that don't. There is also a cost subsidy from extra-small and small business customers to residential customers built into current rates. Beyond these examples, however, there are probably only a few situations in the rate making process that could legitimately be considered a subsidy or cost-shift between customers. And unlike the cost shift resulting from rooftop solar, these policies have been fully vetted and directly adopted by the Commission. By contrast, the solar cost shift has not been subject to such transparency.

Rooftop solar companies sometimes claim that other differences in the costs to serve individual customers, such as one customer living further from a substation and therefore using more grid costs, amount to cost shifting between customers akin to the solar cost shift. APS disagrees with this comparison. The rooftop solar issue results from an exponentially growing group of customers that do not pay their fair share for the infrastructure costs necessary to provide them electric services. The example of a customer's location on the grid, on the other hand, is already contemplated by the cost of service process and average cost rate making.

Regarding the second assertion, it is not clear why the alleged existence of other subsidies supports doing nothing to address a known subsidy before the known subsidy gets worse.

Q. ROOFTOP SOLAR COMPANIES ALSO CLAIM THAT THIS ISSUE IS JUST THE SAME AS ENERGY EFFICIENCY. WHAT IS YOUR REPLY?

A. Rooftop solar companies claim that the solar cost-shifting issue is no different than energy efficiency, such as an energy efficient air conditioner or a compact florescent light bulb. APS believes that energy efficiency does in fact face a similar issue, but not nearly to the same level of severity or unfairness to non-participants compared with rooftop solar. Like solar customers, when a residential customer installs an energy efficiency measure they also receive bill savings for all of the unbundled services shown on Table 1, except metering and billing. In this way they also shift costs to other customers.

However, there are key differences between energy efficiency and rooftop solar in this regard. For example, more customers have the opportunity to participate in energy efficiency, including renters, low income customers, customers living in apartments or "doublewides" and others that may be practically excluded from the rooftop solar market. When they do participate in energy efficiency, their monthly kWh and bill savings are typically far lower than a solar customer, who can reduce their usage by 70% or more. In addition, unlike solar generation, APS does not have to provide infrastructure to back up the customer's load when they invest in energy efficiency. Rooftop solar requires a constant connection to the grid to supply voltage and VAR support. And when a customer installs an energy efficiency measure, their load is actually gone, not just partially supplied by on–site generation. If an energy efficiency measure fails—such as when an energy efficient air conditioner fails—the power required to run the air conditioner is no longer needed. By contrast, when a rooftop solar system fails, such as when clouds pass overhead, the solar customer's entire load must suddenly be served. Furthermore, a customer with energy efficiency is not able to bank energy savings from one hour to net metered against consumption in another. For these reasons and others, the cost shifting from participants to non-participants resulting from energy efficiency is very different and far less severe than with rooftop solar.

VIII. <u>TIMING OF SOLUTION</u>

Q. WHY IS APS SEEKING TO SOLVE THIS PROBLEM NOW?

A. APS believes that because of the recent rapid growth in customers installing solar rooftop systems, the issue needs to be addressed now, rather than waiting for the next rate case, which at the earliest would conclude in July 2016. As described by Mr. Bernosky, rooftop solar participation has grown from 900 customers in early 2009 to approximately 18,000 customers today. And this number is currently growing by approximately 500 units per month. The $15 to $20 million in costs shifted every year due to Net Metering could easily grow by another $6 million per year and double by the next rate case. In addition, if the Commission desires to "grandfather" existing solar customers, the rapid growth in the number of solar customers would make such a policy extremely difficult, if not impossible, to implement in the next rate case.

Q. SHOULDN'T THE NET METERING COST SHIFT BE ADDRESSED IN A RATE CASE?

A. No. From a practical or policy perspective, there is no reason why the issue needs to be handled in a rate case. Although rate cases involve assessing cost recovery, cost allocations between rate groups and rate design issues, the solar cost shift can be addressed without a general reassessment of all of these issues.

Q. WHY IS THAT?

A. First, APS is not seeking an increase in cost recovery or revenues beyond the test year levels established in the last rate case. The customers installing solar today did not have solar during the 2010 test year. Therefore, any revenue changes from the proposed solutions would only limit revenue reductions that have not yet occurred, and thus necessarily occur after the test year. Second, the proposed solutions do not redesign or reset rates for the general classes of customers; they are limited to new solar customers and rely on existing approved rate schedules. Third, the cost shifting issues are also confined to rooftop solar; they can be evaluated directly and need not be assessed in a broader cost of service or cost allocation study. And fourth, there are sufficient tools and options available to resolve the solar cost shifting issue today, outside of a general rate case. Given these realities, and that waiting will only exacerbate the cost shift and potentially preclude grandfathering, the cost shift issue can and should be addressed now.

IX. PROPOSED SOLUTION OPTIONS

Q. WHAT IS THE FOCUS OF APS'S PROPOSED SOLUTION?

A. The proposed solution is focused on residential customers because they have both a high participation in rooftop solar and a high prevalence of contributing to fixed infrastructure costs through variable energy charges.

Q. WHAT DOES APS PROPOSE AS A SOLUTION?

A. APS proposes two potential options to address this issue: a Net Metering Option and a Bill Credit Option. The Net Metering Option would require residential customers that install rooftop solar to move to the existing ECT-2 rate, which is a time-of-use rate with an on-peak demand charge. Customers may continue to participate in the current Net Metering program. Under the Bill Credit Option, APS would provide a bill credit for the total output of the solar generator at a market-based rate. Both options essentially modify the eligibility requirements for the current Net Metering and Net Billing programs—Rate Rider Schedule EPR-6 and EPR-2, respectively.

Q. HOW DOES APS PROPOSE TO TREAT CUSTOMERS WITH EXISTING ROOFTOP SOLAR SYSTEMS?

A. APS proposes that "Existing Solar" customers be grandfathered from either of these proposals for 20 years, until April 15, 2034. Existing Solar customers include (1) those that have already installed and interconnected rooftop solar (or another qualifying renewable generator); and (2) additional customers that submit to APS an interconnection application and a signed contract with a solar installer before October 15, 2013, and complete the interconnection within 180 days of that submission. Customers that previously installed solar, but never interconnected with APS's grid, would have to complete the process identified in (2) above by the same specified dates. The grandfathering provision would apply to the current homeowner and would not be transferrable to subsequent owners. Any new solar customers that do not meet these grandfathering provisions would be subject to APS's proposed changes in the program.

Existing Solar customers that are grandfathered from the new Net Metering program will otherwise be treated like any other customer, including being subject to future rate changes, such as changes in rate designs and policies, rate increases, or other changes in retail rates that may occur from time to time.

Q. PLEASE DESCRIBE THE ECT-2 RATE.

A. The ECT-2 rate is a time-of-use rate with a demand charge that APS has offered since 2006. It has a basic service charge, on-peak and off-peak kWh charges and a demand (kW) charge that applies to on-peak hours only. The peak hours are 12:00 noon to 7:00 p.m. on weekdays, excluding designated holidays. The energy and demand charges are also differentiated by season—summer (May through October) and winter (November through April). The basic service charge recovers metering and billing costs; the demand charge recovers some, but not all, of the infrastructure costs; the kWh charges recover the fuel cost, some of the infrastructure costs, and all of the fixed budget, public policy program costs. The existing Rate Schedule ECT-2, along with the revised Rate Rider Schedules EPR-6 and EPR-2, are provided as Attachment CAM-5.

Q. DOES THE ECT-2 RATE ADEQUATELY ADDRESS THE COST SHIFT PROBLEM?

A. To a large extent, yes. Although the ECT-2 rate does not perfectly recover the infrastructure and fixed budget costs, APS believes that the rate as currently designed would go a long way to resolving the cost shift issue.

Q. IS APS PROPOSING ANY ADDITIONAL REVISIONS TO ECT-2 AT THIS TIME?

A. No. As I stated previously, APS believes that the ECT-2 rate would significantly improve the cost shifting issue.

Q. IS APS PROPOSING ANY ADDITIONAL CHANGES TO THE NET METERING PROGRAM?

A. No. Other than limiting participation in Net Metering to the ECT-2 rate for new residential solar customers, APS is not proposing any additional changes to the Net Metering program at this time.

Q. PLEASE PROVIDE DETAILS REGARDING THE NET METERING OPTION PROPOSAL.

A. The proposed Net Metering Option is as follows:

- All customers with on-site generation are required to interconnect with APS's grid, according to the approved rules and processes, and be served under a partial requirements rate rider schedule.

- New Solar Customers would be required to receive service under Rate Schedule ECT-2, or any successor rate schedule. Participation in the Net Metering or Net Billing programs, Rate Rider Schedules EPR-6 and EPR-2 or successor schedules, would be limited to those customers taking service under Rate Schedule ECT-2.

- New Solar customers may continue to participate in the Net Metering or Net Billing programs as they are revised from time to time. These programs are subject to change in the future as directed by the Commission.

- Existing Solar Customers may continue to be served under their current rate options or successor rates, as they are revised from time to time. This provision will apply through April 15, 2034 and will not be transferrable to subsequent homeowners.

Q. PLEASE EXPLAIN THE PROPOSED BILL CREDIT OPTION.

A. Under the Bill Credit Option, all of the solar energy from a customer's rooftop unit would be credited to the customer's bill at a market-based price, rather than the current practice of crediting solar generation at the full retail rate. In other words, the value of all the solar energy produced from the rooftop unit would be credited to the customer's bill, rather than offsetting their energy consumption or being treated as excess generation under the Net Metering or Net Billing programs. Under the Bill Credit Option, solar energy would continue to provide bill savings to the customer, except that those savings would now reflect a market-based price.

Q. HOW WOULD THE MARKET PRICE FOR THE BILL CREDIT OPTION BE DETERMINED?

A. The credit price under the Bill Credit Option would be based on the one-year forward market price for electricity at the Palo Verde trading hub, which is a major energy trading center in the Phoenix metro area. One-year forward prices are market clearing prices that provide compensation for both fuel and power plant infrastructure costs. The price under the Bill Credit Option is shaped to the hourly production profile for a rooftop solar generator. This is achieved by (i) taking the forward monthly block prices for the Palo Verde trading hub for the next 12 months; (ii) translating these monthly block prices into an hourly price curve using hourly historical prices from the California Independent System Operator from the previous 12 month period; and (iii) applying the resulting hourly Palo Verde forward prices to a standard hourly production profile for residential rooftop solar. These hourly credit values are then adjusted upward by 7.0% to reflect average distribution line losses and adjusted downward by

$0.0025 per kWh to reflect system integration costs. This price is currently about $0.04 per kWh and would be revised annually.

Q. WHY IS APS RECOMMENDING THIS MARKET PRICE?

A. The Company believes that this price appropriately reflects the avoided cost of an alternative source of generation that would be offset by the rooftop solar generation. It reflects current fuel and power plant capacity costs with the relevant adjustments to reflect the distributed nature of rooftop solar.

Q. DID APS CONSIDER OTHER POTENTIAL METHODS FOR SETTING THE PRICE UNDER THE BILL CREDIT OPTION?

A. Yes, APS considered several methods. For example, the price could be based on the simple average of the total firm and non-firm purchase rates in Rate Rider Schedule EPR-6, which are currently used to credit the excess generation remaining at the end of the year for net metering customers. This price would reflect the fuel costs, power plant costs and line losses that are avoided because of rooftop solar. It would be revised on an annual basis and would currently be about $0.03 per kWh. This method of calculating the bill credit would provide the lowest value for customers installing rooftop solar, but also results in the lowest cost to non-solar customers.

The credit price could also be based on the average embedded costs for fuel and a portion of the power plant costs that are currently reflected in retail rates. This credit price could be derived by taking the fuel costs and 50% of the power plant costs reflected in rates for the residential class as reflected in the cost of service and cost recovery from the most recent rate case. As described earlier, using these costs would result in a bill credit at this time of approximately $0.054 per kWh for residential customers. A credit calculated using this method would provide a higher value for solar customers, but at a higher cost to non-participants than under APS's recommendation.

If one concluded that solar generation has value that is not reflected in pure wholesale market pricing, a market price for solar generation could be developed based on a long-term utility-scale solar purchase power price, adjusted for losses and capacity value. Such a value would likely be between $0.08 and $0.09 per kWh today and could also be periodically refreshed to reflect current market conditions for solar power. A bill credit using this method would offer the highest value to customers installing rooftop solar, but would also result in the highest costs for non-participating customers.

Q. WOULD A SOLAR PURCHASED POWER PRICE BE CONSIDERED THE UPPER END OF ANY METHOD TO DETERMINE A MARKET PRICE?

A. Yes. A market or bid price for a long-term purchase of utility scale solar power should be considered an upper range for the bill credit price because it would provide basically all of the benefits— in terms of utility costs savings—ascribed to rooftop solar. For example, a solar generator could be located at or near APS's load center, e.g., Phoenix, and provide the same reductions in avoided generation and fuel costs (and potentially transmission costs) resulting from rooftop solar. In addition, it would provide any of the additional benefits of rooftop solar purported by rooftop solar companies (many of which APS does not consider valid) such as additional environmental benefits, renewable portfolio standard cost savings, fuel hedge costs and other "value of solar" items.

Using the cost for a long-term solar purchase power agreement is a far more reasonable approach than the "value of solar" concept found in studies such as the Cross Border Study. Cross Border proclaims rooftop solar values above $0.22 per kWh. But if APS customers can obtain solar generation for $0.08 and $0.09 per kWh today, it would be imprudent to pay $0.22 per kWh to customers with rooftop solar.

Q. DOES APS RECOMMEND ANY LIMITS OR CAPS IN PARTICIPATION FOR THE BILL CREDIT OPTION?

A. Because the Bill Credit Option is based on the Palo Verde forward market, APS does not propose any participation limitations. The need for limitations would be different if the credit price is based on a different methodology. If the resulting credit price for rooftop solar generation reflected the near-term avoided costs of conventional generation, such as the PURPA purchase price or the average costs for fuel and limited power plant costs (e.g., 50%) embedded in current rates, the outcome would be the same as the Bill Credit Option and program limits or caps in participation would not be necessary or warranted.

However, if the credit price reflected the long-term utility-scale solar PPA concept, participation would have to be limited to a certain amount of MWs, with all additional rooftop solar being credited at a price that reflects near-term avoided generation costs. This is because a PPA price would be more expensive than the cost of conventional generation and unlimited participation would result in significant cost burdens on customers. In contrast, PURPA provides a free "put option" qualifying generators by requiring APS to purchase the generating unit's output. However, this unlimited purchase obligation does not unduly harm customers because the purchase price is based on near-term avoided generation costs.

Q. HOW DO THESE OPTIONS IMPACT THE POTENTIAL BILL SAVINGS FROM ROOFTOP SOLAR?

A. Typical monthly bill impacts for customers with rooftop solar under the current and proposed Net Metering program are provided in Attachment CAM-3. As shown, the monthly bill savings for Net Metering customers under the current program range from 14 to 16 cents per kWh depending on the retail rate, the amount of solar installed and other factors. The likely bill savings under the proposed Net Metering Option (rate ECT-2) will typically range from 6 to 10 cents per kWh depending again on the customer's retail rate prior to adding rooftop solar, the amount of solar added and the reduction in monthly peak demand resulting from the solar unit. Under the Bill Credit Option, the monthly bill savings (per kWh) will be solely determined by the credit price, which APS is proposing to be roughly $0.04 per kWh.

X. OPTIONS CONSIDERED

Q. HAVE OTHER UTILITIES IMPLEMENTED SOLUTIONS TO ADDRESS THE SOLAR COST SHIFTING ISSUE?

A. Yes, but efforts have been very limited. Although the cost shift caused by rooftop solar is receiving national attention, not many utilities have implemented solutions to date. And those that have are smaller utilities in smaller markets, and the solutions have only been implemented as optional pilot programs. A few municipalities have implemented or proposed solutions similar to the Bill Credit Option, such as a value-of-solar or market purchase model. One utility has implemented limited stand-by charges for residential solar customers with larger generators, and another utility has proposed, but not yet implemented, a mandatory demand charge rate for residential solar customers.

Q. WHAT OPTIONS DID APS CONSIDER TO ADDRESS THIS ISSUE?

A. APS assessed several potential options for addressing the cost shift—both Net Metering concepts and bill credit approaches. For rate concepts, APS explored a variety of rate designs that provided more appropriate recovery of fixed costs. These included, in addition to the existing ECT-2 rate, rates with higher basic service charges, time-of-use based demand charges, non-timed demand charges, various standby rate concepts, as well as a modified Net Metering concept where the solar generation only nets against certain non-infrastructure kWh charges on the bill.

For the bill credit options, APS assessed a variety of valuation concepts to derive the market purchase price for the solar energy. These included the current PURPA purchase rates for renewable generation, short run market prices for electricity capacity and energy with certain adjustments for the distributed nature of rooftop solar, a long-run purchase power price for solar energy with similar adjustments, a feed-in tariff and value-of-solar concepts.

Q. HOW DID APS ASSESS THESE OPTIONS?

A. APS evaluated these options on a number of criteria, including the effectiveness in resolving the cost-shifting problem, the transparency of the solution and underlying rates and charges, the stability of the solution over time, the complexity of the bill calculation and ease of customer understanding, the bill impacts on solar customers and other factors.

Q. WHAT DID APS CONCLUDE?

A. One key conclusion is that there is no simple answer that perfectly addresses this problem without considerations or limitations. That said, many of the options, including the two options proposed, would effectively resolve the issue with only minor concerns.

Q. WHAT ARE THE ADVANTAGES AND CONCERNS OF THE NET METERING OPTIONS?

A. Most, if not all, of the Net Metering options would significantly reduce the cost-shifting from rooftop solar, would be moderately transparent, and would be relatively stable over time. On the other hand, the structure or design of individual rates can be modified over time, which can result in uncertainty. The other advantage of the Net Metering options is that they preserve the customer's ability to supply a portion of their own load and export excess power to the grid. However, several of the concepts, such as the standby charges and modified Net

Metering concept, would likely be complicated to compute and/or difficult to explain in a way that would facilitate informed decision-making by the customer.

In the end, APS selected the ECT-2 rate because, although not perfect, it would significantly reduce the cost shifting problem, is an appropriate rate design for solar customers, is an existing rate that has already been accepted by thousands of customers, and would be relatively straightforward to implement.

Q. WHAT ARE THE ADVANTAGES AND CONCERNS OF THE BILL CREDIT OPTIONS?

A. Bill credit options can provide a transparent price signal that is understandable and the same for all customers—it doesn't vary according to usage patterns or individual retail rate designs. The purchase prices can also be adjusted periodically to appropriately reflect current market conditions. On the other hand, some of the pricing options could vary significantly over time, and therefore be less predictable for customers. Bill credit options also involve a new arrangement for solar customers where they receive credit for their solar generation based on a specified price, rather than as an offset against household consumption that is effectively credited at the utility's retail rate.

XI. <u>ADJUSTMENT SCHEDULE LFCR</u>

Q. PLEASE DESCRIBE ADJUSTMENT SCHEDULE LFCR.

A. The LFCR adjustor was approved in the last rate case and implemented in 2013. It provides partial cost recovery for certain infrastructure costs that would otherwise be unrecovered due to energy efficiency and rooftop solar programs. The adjustor includes the distribution and some of the transmission infrastructure costs shown on Table 1. However, it excludes the power plant infrastructure costs and all of the fixed budget public policy program items.

In addition, the adjustor only applies to new rooftop solar or energy efficiency measures added between rate cases. This is because any unrecovered infrastructure costs are addressed in a rate case. At the conclusion of a rate case, unrecovered infrastructure costs are placed into and increase rates and the LFCR adjustor is reset to zero.

The adjustment is derived by determining an LFCR rate per kWh for residential and business customers sufficient to permit recovery of the infrastructure costs contemplated by the LFCR. This rate is then applied to the growth in energy efficiency and rooftop solar since the last rate case, which concluded in July 2012.

Q. DOESN'T THE LFCR ADDRESS THE COST SHIFTING PROBLEM?

A. No, it doesn't. The issue at hand is that solar customers shift costs to non-solar customers by not paying infrastructure costs. Although the LFCR collects a portion of those fixed costs between rate cases (a charge that solar customers avoid), all fixed costs collected by the LFCR are put into rates and the LFCR is reset to zero in each rate case. As a result, rates for non-solar customers will increase due to the cost shift. The LFCR simply does not impact the rate increases caused by the solar cost shift.

Q. WHAT IS APS PROPOSING TO ENSURE THAT THE INFRASTRUCTURE COSTS ARE NOT DOUBLE RECOVERED THROUGH THE LFCR?

A. If either of the proposed solutions is adopted, the unrecovered infrastructure costs from new solar systems would be significantly reduced. Therefore, to avoid any potential double recovery, APS would not include the kWh associated with new solar installations in the annual LFCR calculation.

XII. CONCLUSION

Q. PLEASE PROVIDE CONCLUDING REMARKS FOR YOUR DIRECT TESTIMONY?

A. My testimony summarizes APS's requests that the Commission authorize:

1. The Net Metering Option to limit the eligibility for the Net Metering and Net Billing programs, Rate Rider Schedule EPR-6 and Rate Rider Schedule EPR-2 respectively, to residential customers enrolled in Rate Schedule ECT-2 as expressed in the proposed revisions to those rate rider schedules; or
2. As an alternative, The Bill Credit Option which limits the eligibility for residential rooftop solar to customers enrolled in the Rate Rider Schedule EPR-7, which is a Bill Credit Option;
3. The request that these proposed changes would not apply to residential customers who have already installed solar generation, per the timing and other details proposed by the Company; and
4. The proposed revisions to the annual filing for Adjustment Schedule LFCR.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

DECLARATION

I declare that I have personal knowledge of the foregoing testimony, and that the foregoing is true to the best of my knowledge under penalty of perjury.

Signed: ______________
Charles A. Miessner

Date: 7/12/2013

Charles Miessner
Statement of Qualifications

Charles Miessner has over 30 years experience in the electric utility industry in the areas of pricing, planning, and business development for both utilities and private energy companies. Prior to joining Arizona Public Service, he served in management and leadership positions for Progress Energy, Tucson Electric Power, AES - New Energy, New West Energy and The Salt River Project. His accomplishments include: developing integrated resource planning methods and models and starting up demand-side programs at Progress Energy and Tucson Electric Power; participating in the start-up of AES- New Energy; directing strategic planning, pricing, origination, and government affairs for New West Energy; and developing and managing rate planning and implementation for Arizona Public Service. Charles has appeared before regulators and legislators on energy issues in Arizona, California, Nevada and New Mexico.

APS Current Rooftop Solar Participation

	Customer Count CY 2012	Net-Metering Customer Count June 2013	Net-Billing Customer Count June 2013	Total Solar Customers June 2013	Percent of Total Solar Participation
RESIDENTIAL					
Inclining Block	434,491	6,294	33	6,327	35.8%
TOU-Energy	390,255	10,009	38	10,047	56.8%
TOU-Demand	98,643	638	12	650	3.7%
Subtotal	923,389	16,941	83	17,024	96.2%
BUSINESS					
Extra Small	83,767	295	16	311	1.8%
Small	30,094	104	5	109	0.6%
Medium	4,235	189	1	190	1.1%
Large	958	58	2	60	0.3%
Extra Large	62	2	-	2	0.0%
Subtotal	119,116	648	24	672	3.8%
TOTAL	**1,042,505**	**17,589**	**107**	**17,696**	**100.0%**

SOLAR BILL - ILLUSTRATIVE EXAMPLE
SUMMER MONTH, CURRENT PROGRAM
Customer currently on Inclining Block (IB) Rate

Before Solar

	IB Rate	Units		Bill	IB Rate
Basic Service Charge	0.285	30	$	8.55	0.285
System Benefits	0.00297	1,600	$	4.75	0.00297
Transmission	0.00520	1,600	$	8.32	0.00520
Delivery kWh	0.02700	1,600	$	43.20	0.02700
Generation					
kWh1	0.06170	400	$	24.68	0.06170
kWh2	0.10300	400	$	41.20	0.10300
kWh3	0.12650	800	$	101.20	0.12650
kWh4	0.13740	-	$	-	0.13740
Adjustments:					
PSA Historic	0.002333	1,600	$	3.73	0.002333
PSA Forward	(0.001004)	1,600	$	(1.61)	(0.001004)
DSMAC	0.002717	1,600	$	4.35	0.002717
RES			$	3.83	
TCA	0.005403	1,600	$	8.64	0.005403
Subtotal			$	250.84	
LFCR	0.2%		$	0.50	
Taxes and Gov't Fees	9.50%		$	23.88	
Total			**$**	**275.22**	

$ per kWh Total Bill - Summer 0.1720

Solar kWh applied t
Bill sa
E
LFCR recovery

Summer Usage and Solar Generation

	Load	Solar	Billed
kWh	1,600	1,000	600

SOLAR BILL - ILLUSTRATIVE EXAMPLE
WINTER MONTH, CURRENT PROGRAM
Customer currently on Inclining Block (IB) Rate

Before Solar

	IB Rate	Units		Bill	IB Rate
Basic Service Charge	0.285	30	$	8.55	0.285
System Benefits	0.00297	900	$	2.67	0.00297
Transmission	0.00520	900	$	4.68	0.00520
Delivery kWh	0.02700	900	$	24.30	0.02700
Generation					
kWh1	0.05900	900	$	53.10	0.05900
kWh2					
kWh3					
kWh4					
Adjustments:					
PSA Historic	0.002333	900	$	2.10	0.002333
PSA Forward	(0.001004)	900	$	(0.90)	(0.001004)
DSMAC	0.002717	900	$	2.45	0.002717
RES			$	3.83	
TCA	0.005403	900	$	4.86	0.005403
Subtotal			$	105.64	
LFCR	0.2%		$	0.21	
Taxes and Gov't Fees	9.50%		$	10.06	
Total			**$**	**115.91**	

$ per kWh Total Bill - Winter 0.1288

Solar kWh applied t
Bill sa
E
LFCR recovery

Winter Usage and Solar Generation

	Load	Solar	Billed
kWh	900	750	150

$ per kWh Total Bill - Annual AVG	0.1426
$ per kWh Total Bill - Annual AVG w/tax	0.1565

Savings Summary	**Savings $**	**Savings %**	**Savings $/kWh**	w/o taxes **$/kWh**	**kWh Weight**
Summer Bill	182.58	66%	0.1826	0.1667	57%
Winter Bill	85.26	74%	0.1137	0.1038	43%
Avg Bill	133.92	68%	**0.1530**	**0.1397**	

With Solar

Units		Bill
30	$	8.55
600	$	1.78
600	$	3.12
600	$	16.20
400	$	24.68
200	$	20.60
-	$	-
-	$	-
600	$	1.40
600	$	(0.60)
600	$	1.63
	$	3.83
600	$	3.24
	$	84.43
	$	0.17
	$	8.04
	$	**92.64**
Bill savings	$	182.58
o current bill		1,000
vings $/kWh		0.1826
Bill savings %		66%
(@ $0.0311)	$	31.10

With Solar

Units		**Bill**
30	$	8.55
150	$	0.45
150	$	0.78
150	$	4.05
150	$	8.85
150	$	0.35
150	$	(0.15)
150	$	0.41
	$	3.83
150	$	0.81
	$	27.93
	$	0.06
	$	2.66
	$	**30.65**
Bill savings	$	85.26
ɔ current bill		750
vings $/kWh		0.1137
3ill savings %		74%
(@ $0.0311)	$	23.33

SOLAR BILL - ILLUSTRATIVE EXAMPLE
SUMMER MONTH, CURRENT PROGRAM
Customer currently on Time-of-Use Energy (TOU-E) Rate

	Before Solar				With Solar			
	TOU-E Rate	**Units**		**Bill**	**TOU-E Rate**	**Units**		**Bill**
Basic Service Charge	0.556	30	$	16.68	0.556	30	$	16.68
System Benefits	0.00297	1,600	$	4.75	0.00297	600	$	1.78
Transmission	0.00520	1,600	$	8.32	0.00520	600	$	3.12
Delivery kWh	0.02700	1,600	$	43.20	0.02700	600	$	16.20
Generation								
On-Pk kWh	0.20960	388	$	81.32	0.20960	-	$	-
Off-Pk kWh	0.02601	1,212	$	31.52	0.02601	712	$	18.52
Adjustments:								
PSA Historic	0.002333	1,600	$	3.73	0.002333	600	$	1.40
PSA Forward	(0.001004)	1,600	$	(1.61)	(0.001004)	600	$	(0.60)
DSMAC	0.002717	1,600	$	4.35	0.002717	600	$	1.63
RES			$	3.83			$	3.83
TCA	0.005403	1,600	$	8.64	0.005403	600	$	3.24
Subtotal			$	204.73			$	65.80
LFCR	0.2%		$	0.41			$	0.13
Taxes and Gov't Fees	9.50%		$	19.49			$	6.26
Total			**$**	**224.63**			**$**	**72.19**

$ per kWh Total Bill - Summer	0.1404

Bill savings	$ 152.44
Solar kWh applied to current bill	924
Bill savings $/kWh	0.1650
Bill savings %	68%
LFCR recovery (@ $0.0311)	$ 28.73

Summer Usage and Solar Generation

	Load	Solar	Billed
Total kWh	1,600	1,000	600
On-Pk kWh	388	500	0
Off-Pk kWh	1,212	500	712

SOLAR BILL - ILLUSTRATIVE EXAMPLE
WINTER MONTH, CURRENT PROGRAM
Customer currently on Time-of-Use Energy (TOU-E) Rate

	Before Solar			With Solar		
	TOU-E Rate	**Units**	**Bill**	**TOU-E Rate**	**Units**	**Bill**
Basic Service Charge	0.556	30	$ 16.68	0.556	30	$ 16.68
System Benefits	0.00297	900	$ 2.67	0.00297	150	$ 0.45
Transmission	0.00520	900	$ 4.68	0.00520	150	$ 0.78
Delivery kWh	0.02700	900	$ 24.30	0.02700	150	$ 4.05
Generation						
On-Pk kWh	0.16330	152	$ 24.82	0.16330	-	$ -
Off-Pk kWh	0.02599	748	$ 19.44	0.02599	373	$ 9.69
Adjustments:						
PSA Historic	0.002333	900	$ 2.10	0.002333	150	$ 0.35
PSA Forward	(0.001004)	900	$ (0.90)	(0.001004)	150	$ (0.15)
DSMAC	0.002717	900	$ 2.45	0.002717	150	$ 0.41
RES			$ 3.83			$ 3.83
TCA	0.005403	900	$ 4.86	0.005403	150	$ 0.81
Subtotal			$ 104.93			$ 36.90
LFCR	0.2%		$ 0.21			$ 0.07
Taxes and Gov't Fees	9.50%		$ 9.99			$ 3.51
Total			**$ 115.13**			**$ 40.48**

$ per kWh Total Bill 0.1279

Bill savings	$ 74.65
Solar kWh	639
Bill savings $/kWh	0.1169
Bill savings %	65%
LFCR recovery (@ $0.0311)	$ 19.86

Winter Usage and Solar Generation

	Load	Solar	Billed
Total kWh	900	750	150
On-Pk kWh	152	375	0
Off-Pk kWh	748	375	373

$ per kWh Total Bill - Annual AVG	0.1239
$ per kWh Total Bill - Annual AVG w/tax	0.1359

Savings Summary	**Savings $**	**Savings %**	**Savings $/kWh**	w/o taxes **$/kWh**	**kWh Weight**
Summer Bill	152.44	68%	0.1650	0.1507	59%
Winter Bill	74.65	65%	0.1169	0.1068	41%
	113.55	67%	0.1453	0.1327	

SOLAR BILL - ILLUSTRATIVE EXAMPLE
SUMMER MONTH, PROPOSED RATE OPTION
Customer currently on Inclining Block (IB) Rate
Move to existing Rate ECT-2 (time-of-use with demand charge)

	Current Program - Before Solar					Proposed Concept - ECT-2 existing rate			
	IB Rate	**Units**		**Bill**		**ECT-2 Rate**	**Units**		**Bill**
Basic Service Charge	0.285	30	$	8.55	Basic Service Charge	0.556	30	$	16.68
System Benefits	0.00297	1,600	$	4.75	System Benefits	0.00297	600	$	1.78
Transmission	0.00520	1,600	$	8.32	Transmission	0.00520	600	$	3.12
Delivery kWh	0.02700	1,600	$	43.20	Delivery kWh	0.01400	600	$	8.40
					Delivery kW	4.500	6.5	$	29.25
Generation					Generation				
kWh1	0.06170	400	$	24.68	On-Pk kWh	0.06650	-	$	-
kWh2	0.10300	400	$	41.20	Off-Pk kWh	0.02200	712	$	15.66
kWh3	0.12650	800	$	101.20	On-Pk kW	9.000	6.5	$	58.50
kWh4	0.13740	-	$	-					
Adjustments:					**Adjustments:**				
PSA Historic	0.002333	1,600	$	3.73	PSA Historic	0.002333	600	$	1.40
PSA Forward	(0.001004)	1,600	$	(1.61)	PSA Forward	(0.001004)	600	$	(0.60)
DSMAC	0.002717	1,600	$	4.35	DSMAC	0.002717	600	$	1.63
RES			$	3.83	RES			$	3.83
TCA	0.005403	1,600	$	8.64	TCA	0.005403	600	$	3.24
Subtotal			$	250.84	**Subtotal**			$	142.89
LFCR	0.2%		$	0.50	LFCR			$	0.29
Taxes and Gov't Fees	9.50%		$	23.88	Taxes and Gov't Fees			$	13.60
Total			**$**	**275.22**	**Total**			**$**	**156.78**

$ per kWh Total Bill 0.1720

Bill savings	$	118.44
Solar kWh applied to current bill		944
Bill savings $/kWh		0.1255
Bill savings %		43%
LFCR recovery (@ $0.0311)	$	29.36

Summer Usage and Solar Generation

	Load	Solar	Billed
Total kWh	1,600	1,000	600
On-Pk kWh	388	500	0
Off-Pk kWh	1,212	500	712
On-Pk kW	7.2	0.7	6.5
assumed solar kW reduction	10%		

SOLAR BILL - ILLUSTRATIVE EXAMPLE
WINTER MONTH, PROPOSED RATE OPTION
Customer currently on Inclining Block (IB) Rate
Move to existing Rate ECT-2 (time-of-use with demand charge)

Current Program - Before Solar

	IB Rate	Units		Bill
Basic Service Charge	0.285	30	$	8.55
System Benefits	0.00297	900	$	2.67
Transmission	0.00520	900	$	4.68
Delivery kWh	0.02700	900	$	24.30
Generation				
kWh1	0.05900	900	$	53.10
kWh2				
kWh3				
kWh4				
Adjustments:				
PSA Historic	0.002333	900	$	2.10
PSA Forward	(0.001004)	900	$	(0.90)
DSMAC	0.002717	900	$	2.45
RES			$	3.83
TCA	0.005403	900	$	4.86
Subtotal			$	105.64
LFCR	0.2%		$	0.21
Taxes and Gov't Fees	9.50%		$	10.06
Total			$	**115.91**
	$ per kWh Total Bill			0.1288

Proposed Concept - ECT-2 existing rate

	ECT-2 Rate	Units		Bill
Basic Service Charge	0.556	30	$	16.68
System Benefits	0.00297	150	$	0.45
Transmission	0.00520	150	$	0.78
Delivery kWh	0.01590	150	$	2.39
Delivery kW	2.400	4.7	$	11.28
Generation				
On-Pk kWh	0.03340	-	$	-
Off-Pk kWh	0.01700	373	$	6.34
On-Pk kW	6.900	4.7	$	32.43
Adjustments:				
PSA Historic	0.002333	150	$	0.35
PSA Forward	(0.001004)	150	$	(0.15)
DSMAC	0.002717	150	$	0.41
RES			$	3.83
TCA	0.005403	150	$	0.81
Subtotal			$	75.60
LFCR			$	0.15
Taxes and Gov't Fees			$	7.20
Total			$	**82.95**
		Bill savings	$	32.96
		Solar kWh applied to current bill		639
		Bill savings $/kWh		0.0516
		Bill savings %		28%
		LFCR recovery (@ $0.0311)	$	19.86

Winter Usage and Solar Generation

	Load	Solar	Billed
Total kWh	900	750	150
On-Pk kWh	152	375	0
Off-Pk kWh	748	375	373
On-Pk kW	5.2	0.5	4.7
assumed solar kW reduction	10%		

$ per kWh Total Bill - Annual AVG	0.1426
$ per kWh Total Bill - Annual AVG w/tax	0.1565

Savings Summary	**Savings $**	**Savings %**	**Savings $/kWh**	w/o taxes **$/kWh**	**kWh Weight**
Summer Bill	118.44	43%	0.1255	0.1146	60%
Winter Bill	32.96	28%	0.0516	0.0471	40%
Avg Bill	75.70	39%	**0.0959**	**0.0876**	

SOLAR BILL - ILLUSTRATIVE EXAMPLE
SUMMER MONTH, PROPOSED RATE OPTION
Customer currently on Time-of-Use Energy Rate (TOU-E)
Move to existing Rate ECT-2 (time-of-use with demand charge)

	Current Program - Before Solar			Proposed Concept - ECT-2 existing rate		
	TOU-E Rate	**Units**	**Bill**	**ECT-2 Rate**	**Units**	**Bill**
Basic Service Charge	0.556	30	$ 16.68	0.556	30	$ 16.68
System Benefits	0.00297	1,600	$ 4.75	0.00297	600	$ 1.78
Transmission	0.00520	1,600	$ 8.32	0.00520	600	$ 3.12
Delivery kWh	0.02700	1,600	$ 43.20	0.01400	600	$ 8.40
Delivery kW				4.500	6.5	$ 29.25
Generation						
On-Pk kWh	0.20960	388	$ 81.32	0.06650	-	$ -
Off-Pk kWh	0.02601	1,212	$ 31.52	0.02200	712	$ 15.66
On-Pk kW				9.000	6.5	$ 58.50
Adjustments:						
PSA Historic	0.002333	1,600	$ 3.73	0.002333	600	$ 1.40
PSA Forward	(0.001004)	1,600	$ (1.61)	(0.001004)	600	$ (0.60)
DSMAC	0.002717	1,600	$ 4.35	0.002717	600	$ 1.63
RES			$ 3.83			$ 3.83
TCA	0.005403	1,600	$ 8.64	0.005403	600	$ 3.24
Subtotal			$ 204.73			$ 142.89
LFCR	0.2%		$ 0.41			$ 0.29
Taxes and Gov't Fees	9.50%		$ 19.49			$ 13.60
Total			**$ 224.63**			**$ 156.78**

$ per kWh Total Bill	0.1404

Bill savings	$ 67.85
Solar kWh applied to current bill	944
Bill savings $/kWh	0.0719
Bill savings %	30%
LFCR recovery (@ $0.0311)	$ 29.36

Summer Usage and Solar Generation

	Load	Solar	Billed
Total kWh	1,600	1,000	600
On-Pk kWh	388	500	0
Off-Pk kWh	1,212	500	712
On-Pk kW	7.2	0.7	6.5
assumed solar kW reduction	10%		

SOLAR BILL - ILLUSTRATIVE EXAMPLE
WINTER MONTH, PROPOSED RATE OPTION
Customer currently on Time-of-Use Energy Rate (TOU-E)
Move to existing Rate ECT-2 (time-of-use with demand charge)

	Current Program - Before Solar				Proposed Concept - ECT-2 existing rate			
	TOU-E Rate	**Units**		**Bill**	**ECT-2 Rate**	**Units**		**Bill**
Basic Service Charge	0.556	30	$	16.68	0.556	30	$	16.68
System Benefits	0.00297	900	$	2.67	0.00297	150	$	0.45
Transmission	0.00520	900	$	4.68	0.00520	150	$	0.78
Delivery kWh	0.02700	900	$	24.30	0.01590	150	$	2.39
Delivery kW					2.400	4.7	$	11.28
Generation								
On-Pk kWh	0.16330	152	$	24.82	0.03340	-	$	-
Off-Pk kWh	0.02599	748	$	19.44	0.01700	373	$	6.34
On-Pk kW					6.900	4.7	$	32.43
Adjustments:								
PSA Historic	0.002333	900	$	2.10	0.002333	150	$	0.35
PSA Forward	(0.001004)	900	$	(0.90)	(0.001004)	150	$	(0.15)
DSMAC	0.002717	900	$	2.45	0.002717	150	$	0.41
RES			$	3.83			$	3.83
TCA	0.005403	900	$	4.86	0.005403	150	$	0.81
Subtotal			$	104.93			$	75.60
LFCR	0.2%		$	0.21			$	0.15
Taxes and Gov't Fees	9.50%		$	9.99			$	7.20
Total			$	**115.13**			$	**82.95**

$ per kWh Total Bill	0.1279

Bill savings	$	32.18
Solar kWh applied to current bill		639
Bill savings $/kWh		0.0504
Bill savings %		28%
LFCR recovery (@ $0.0311)	$	19.86

Winter Usage and Solar Generation

	Load	Solar	Billed
Total kWh	900	750	150
On-Pk kWh	152	375	0
Off-Pk kWh	748	375	373
On-Pk kW	5.2	0.5	4.7
assumed solar kW reduction	10%		

$ per kWh Total Bill - Annual AVG	0.1239
$ per kWh Total Bill - Annual AVG w/tax	0.1359

Savings Summary	**Savings $**	**Savings %**	**Savings $/kWh**	w/o taxes **$/kWh**	**kWh Weight**
Summer Bill	67.85	30%	0.0719	0.0656	60%
Winter Bill	32.18	28%	0.0504	0.0460	40%
Avg Bill	50.02	29%	**0.0633**	**0.0578**	

SOLAR BILL - ILLUSTRATIVE EXAMPLE
SUMMER MONTH, PROPOSED RATE OPTION
Customer currently on Inclining Block (IB) Rate
Move to New Program - Bill Credit Concept

	Current Program - Before Solar				Proposed Concept - Bill Credit		
	IB Rate	**Units**	**Bill**		**IB Rate**	**Units**	**Bill**
Basic Service Charge	0.285	30	$ 8.55		0.285	30	$ 8.55
System Benefits	0.00297	1,600	$ 4.75		0.00297	1,600	$ 4.75
Transmission	0.00520	1,600	$ 8.32		0.00520	1,600	$ 8.32
Delivery kWh	0.02700	1,600	$ 43.20		0.02700	1,600	$ 43.20
Generation							
kWh1	0.06170	400	$ 24.68		0.06170	400	$ 24.68
kWh2	0.10300	400	$ 41.20		0.10300	400	$ 41.20
kWh3	0.12650	800	$ 101.20		0.12650	800	$ 101.20
kWh4	0.13740	-	$ -		0.13740	-	$ -
Adjustments:							
PSA Historic	0.002333	1,600	$ 3.73		0.002333	1,600	$ 3.73
PSA Forward	(0.001004)	1,600	$ (1.61)		(0.001004)	1,600	$ (1.61)
DSMAC	0.002717	1,600	$ 4.35		0.002717	1,600	$ 4.35
RES			$ 3.83				$ 3.83
TCA	0.005403	1,600	$ 8.64		0.005403	1,600	$ 8.64
Subtotal			$ 250.84				$ 250.84
LFCR	0.2%		$ 0.50				$ 0.50
Taxes and Gov't Fees	9.50%		$ 23.88				$ 23.88
Total			**$ 275.22**				**$ 275.22**
				Solar Credit	**(0.04000)**	**1,000**	**(40.00)**
				Net Bill			**$ 235.22**

$ per kWh Total Bill	0.1720

Bill savings	$ 40.00
Solar kWh applied to current bill	1,000
Bill savings $/kWh	0.0400
Bill savings %	15%
LFCR recovery (@ $0.0311)	$ -

Summer Usage and Solar Generation

	Load	Solar Credit
Total kWh	1600	1000

SOLAR BILL - ILLUSTRATIVE EXAMPLE
WINTER MONTH, PROPOSED RATE OPTION
Customer currently on Inclining Block (IB) Rate
Move to New Program - Bill Credit Concept

	Current Program - Before Solar Winter Bill			Proposed Concept - Bill Credit Winter Bill		
	IB Rate	**Units**	**Bill**	**IB Rate**	**Units**	**Bill**
Basic Service Charge	0.285	30	$ 8.55	0.285	30	$ 8.55
System Benefits	0.00297	900	$ 2.67	0.00297	900	$ 2.67
Transmission	0.00520	900	$ 4.68	0.00520	900	$ 4.68
Delivery kWh	0.02700	900	$ 24.30	0.02700	900	$ 24.30
Generation						
kWh1	0.059	900	$ 53.10	0.059	900	$ 53.10
kWh2						
kWh3						
kWh4						
Adjustments:						
PSA Historic	0.002333	900	$ 2.10	0.002333	900	$ 2.10
PSA Forward	(0.001004)	900	$ (0.90)	(0.001004)	900	$ (0.90)
DSMAC	0.002717	900	$ 2.45	0.002717	900	$ 2.45
RES			$ 3.83			$ 3.83
TCA	0.005403	900	$ 4.86	0.005403	900	$ 4.86
Subtotal			$ 105.64			$ 105.64
LFCR	0.2%		$ 0.21			$ 0.21
Taxes and Gov't Fees	9.50%		$ 10.06			$ 10.06
Total			**$ 115.91**			**$ 115.91**
Solar Credit				**(0.04000)**	**750**	**(30.00)**
Net Bill						**$ 85.91**

$ per kWh Total Bill 0.1288

Bill savings	$ 30.00
Solar kWh applied to current bill	750
Bill savings $/kWh	0.0400
Bill savings %	26%
LFCR recovery (@ $0.0311)	$ -

Winter Usage and Solar Generation

	Load	Solar Credit
Total kWh	900	750

$ per kWh Total Bill - Annual AVG	0.1426
$ per kWh Total Bill - Annual AVG w/tax	0.1565

Savings Summary	**Savings $**	**Savings %**	**Savings $/kWh**	w/o taxes **$/kWh**	**kWh Weight**
Summer Bill	40.00	15%	0.0400	0.0365	57%
Winter Bill	30.00	26%	0.0400	0.0365	43%
Avg Bill	35.00	18%	**0.0400**	**0.0365**	

SOLAR BILL - ILLUSTRATIVE EXAMPLE
SUMMER MONTH, PROPOSED RATE OPTION
Customer currently on Time-of-Use Energy (TOU-E) Rate
Move to New Program - Bill Credit Concept

	Current Program - Before Solar			Proposed Concept - Bill Credit		
	TOU-E Rate	**Units**	**Bill**	**TOU-E Rate**	**Units**	**Bill**
Basic Service Charge	0.556	30	$ 16.68	0.556	30	$ 16.68
System Benefits	0.00297	1,600	$ 4.75	0.00297	1,600	$ 4.75
Transmission	0.00520	1,600	$ 8.32	0.00520	1,600	$ 8.32
Delivery kWh	0.02700	1,600	$ 43.20	0.02700	1,600	$ 43.20
Generation						
On-Pk kWh	0.20960	388	$ 81.32	0.20960	388	$ 81.32
Off-Pk kWh	0.02601	1,212	$ 31.52	0.02601	1,212	$ 31.52
Adjustments:						
PSA Historic	0.002333	1,600	$ 3.73	0.002333	1,600	$ 3.73
PSA Forward	(0.001004)	1,600	$ (1.61)	(0.001004)	1,600	$ (1.61)
DSMAC	0.002717	1,600	$ 4.35	0.002717	1,600	$ 4.35
RES			$ 3.83			$ 3.83
TCA	0.005403	1,600	$ 8.64	0.005403	1,600	$ 8.64
Subtotal			$ 204.73			$ 204.73
LFCR	0.2%		$ 0.41			$ 0.41
Taxes and Gov't Fees	9.50%		$ 19.49			$ 19.49
Total			**$ 224.63**			**$ 224.63**
Solar Credit				**(0.04000)**	**1,000**	**(40.00)**
Net Bill						**$ 184.63**

$ per kWh Total Bill	0.1404

Bill savings	$ 40.00
Solar kWh	1,000
Bill savings $/kWh	0.0400
Bill savings %	18%
LFCR recovery (@ $0.0311)	$ -

Summer Usage and Solar Generation

	Load	Solar Credit
Total kWh	1,600	1,000
On-Pk kWh	388	
Off-Pk kWh	1,212	

SOLAR BILL - ILLUSTRATIVE EXAMPLE
WINTER MONTH, PROPOSED RATE OPTION
Customer currently on Time-of-Use Energy (TOU-E) Rate
Move to New Program - Bill Credit Concept

	Current Program - Before Solar				Proposed Concept - Bill Credit			
	TOU-E Rate	**Units**	**Bill**		**TOU-E Rate**	**Units**	**Bill**
Basic Service Charge	0.556	30	$ 16.68		0.556	30	$ 16.68
System Benefits	0.00297	900	$ 2.67		0.00297	900	$ 2.67
Transmission	0.00520	900	$ 4.68		0.00520	900	$ 4.68
Delivery kWh	0.02700	900	$ 24.30		0.02700	900	$ 24.30
Generation							
On-Pk kWh	0.16330	152	$ 24.82		0.16330	152	$ 24.82
Off-Pk kWh	0.02599	748	$ 19.44		0.02599	748	$ 19.44
Adjustments:							
PSA Historic	0.002333	900	$ 2.10		0.002333	900	$ 2.10
PSA Forward	(0.001004)	900	$ (0.90)		(0.001004)	900	$ (0.90)
DSMAC	0.002717	900	$ 2.45		0.002717	900	$ 2.45
RES			$ 3.83				$ 3.83
TCA	0.005403	900	$ 4.86		0.005403	900	$ 4.86
Subtotal			$ 104.93				$ 104.93
LFCR	0.2%		$ 0.21				$ 0.21
Taxes and Gov't Fees	9.50%		$ 9.99				$ 9.99
Total			**$ 115.13**				**$ 115.13**
				Solar Credit	**(0.04000)**	**750**	**(30.00)**
				Net Bill			**$ 85.13**

$ per kWh Total Bill 0.1279

Bill savings	$ 30.00
Solar kWh	750
Bill savings $/kWh	0.0400
Bill savings %	26%
LFCR recovery (@ $0.0311)	$ -

Winter Usage and Solar Generation

	Load	Solar Credit
Total kWh	900	750
On-Pk kWh	152	
Off-Pk kWh	748	

$ per kWh Total Bill - Annual AVG	0.1239
$ per kWh Total Bill - Annual AVG w/tax	0.1359

Savings Summary	**Savings $**	**Savings %**	**Savings $/kWh**	w/o taxes **$/kWh**	**kWh Weight**
Summer Bill	40.00	18%	0.0400	0.0365	57%
Winter Bill	30.00	26%	0.0400	0.0365	43%
Avg Bill	35.00	21%	**0.0400**	**0.0365**	

Rooftop Solar

Bill Savings vs. Utility Cost Savings

Residential Inclining Block, TOU-Energy Rates

Billing Elements	Cost Type	Charge Type	DE Bill Savings	Utility Cost Savings
Base Rates:				
Metering and Billing	Infrastructure	Monthly		
Delivery	Infrastructure	kWh	X	
Transmission	Infrastructure	kWh	X	
System Benefits	Fixed Budget	kWh	X	
Generation - Capacity	Infrastructure	kWh	X	Partial
Generation - Fuel and variable O&M	Variable	kWh	X	X
Adjustments:				
Renewable Energy Standard	Fixed Budget	kWh, Capped		
Power Supply Adjustor	Variable	kWh	X	X
DSM Cost Adjustment	Fixed Budget	kWh	X	
Environmental Improvement Surcharge	Infrastructure	kWh	X	
Federal Transmission Cost Adjustment	Infrastructure	kWh	X	
Lost Fixed Cost Recovery	Infrastructure	%	X	
Taxes and Government Fees:				
Regulatory Assessment Fee	Variable	%	X	NA
Franchise Fee	Variable	%	X	NA
Sales Taxes	Variable	%	X	NA

Rooftop Solar

Bill Savings vs. Utility Cost Savings

Residential TOU-Demand Rates

Billing Elements	Cost Type	Charge Type	DE Bill Savings	Utility Cost Savings
Base Rates:				
Metering and Billing	Infrastructure	Monthly		
Delivery	Infrastructure	kW, kWh	Low	
Transmission	Infrastructure	kWh	X	
System Benefits	Fixed Budget	kWh	X	
Generation - Capacity	Infrastructure	kW	Low	Partial
Generation - Fuel and variable O&M	Variable	kWh	X	X
Adjustments:				
Renewable Energy Standard	Fixed Budget	kWh, Capped		
Power Supply Adjustor	Variable	kWh	X	X
DSM Cost Adjustment	Fixed Budget	kWh	X	
Environmental Improvement Surcharge	Infrastructure	kWh	X	
Federal Transmission Cost Adjustment	Infrastructure	kWh	X	
Lost Fixed Cost Recovery	Infrastructure	%	X	
Taxes and Government Fees:				
Regulatory Assessment Fee	Variable	%	X	NA
Franchise Fee	Variable	%	X	NA
Sales Taxes	Variable	%	X	NA

Rooftop Solar

Bill Savings vs. Utility Cost Savings

Extra Small Business Customer E-32 XS rate

Billing Elements	Cost Type	Charge Type	DE Bill Savings	Utility Cost Savings
Base Rates:				
Metering and Billing	Infrastructure	Monthly		
Delivery	Infrastructure	kWh	X	
Transmission	Infrastructure	kWh	X	
System Benefits	Fixed Budget	kWh	X	
Generation - Capacity	Infrastructure	kWh	X	Partial
Generation - Fuel and variable O&M	Variable	kWh	X	X
Adjustments:				
Renewable Energy Standard	Fixed Budget	kWh, Capped		
Power Supply Adjustor	Variable	kWh	X	X
DSM Cost Adjustment	Fixed Budget	kWh	X	
Environmental Improvement Surcharge	Infrastructure	kWh	X	
Federal Transmission Cost Adjustment	Infrastructure	kWh	X	
Lost Fixed Cost Recovery	Infrastructure	%	X	
Taxes and Government Fees:				
Regulatory Assessment Fee	Variable	%	X	NA
Franchise Fee	Variable	%	X	NA
Sales Taxes	Variable	%	X	NA

Rooftop Solar

Bill Savings vs. Utility Cost Savings

Small, Medium Business Customer E-32 S, E-32 M rates

Billing Elements	Cost Type	Charge Type	DE Bill Savings	Utility Cost Savings
Base Rates:				
Metering and Billing	Infrastructure	Monthly		
Delivery	Infrastructure	kW, kWh	Low	
Transmission	Infrastructure	kW	Low	
System Benefits	Fixed Budget	kWh	X	
Generation - Capacity	Infrastructure	Hours Use	?	Partial
Generation - Fuel and variable O&M	Variable	kWh	X	X
Adjustments:				
Renewable Energy Standard	Fixed Budget	kWh, Capped		
Power Supply Adjustor	Variable	kWh	X	X
DSM Cost Adjustment	Fixed Budget	kW	Low	
Environmental Improvement Surcharge	Infrastructure	kWh	X	
Federal Transmission Cost Adjustment	Infrastructure	kW	Low	
Lost Fixed Cost Recovery	Infrastructure	%	X	
Taxes and Government Fees:				
Regulatory Assessment Fee	Variable	%	X	NA
Franchise Fee	Variable	%	X	NA
Sales Taxes	Variable	%	X	NA

Rooftop Solar

Bill Savings vs. Utility Cost Savings

Large, Extra Large Business Customer E-32 L, E-34, E-35 rates

Billing Elements	Cost Type	Charge Type	DE Bill Savings	Utility Cost Savings
Base Rates:				
Metering and Billing	Infrastructure	Monthly		
Delivery	Infrastructure	kW	Low	
Transmission	Infrastructure	kW	Low	
System Benefits	Fixed Budget	kWh	X	
Generation - Capacity	Infrastructure	kW	Low	Partial
Generation - Fuel and variable O&M	Variable	kWh	X	X
Adjustments:				
Renewable Energy Standard	Fixed Budget	kWh, Capped		
Power Supply Adjustor	Variable	kWh	X	X
DSM Cost Adjustment	Fixed Budget	kW	Low	
Environmental Improvement Surcharge	Infrastructure	kWh	X	
Federal Transmission Cost Adjustment	Infrastructure	kW	Low	
Lost Fixed Cost Recovery	Infrastructure	NA	NA	
Taxes and Government Fees:				
Regulatory Assessment Fee	Variable	%	X	NA
Franchise Fee	Variable	%	X	NA
Sales Taxes	Variable	%	X	NA

RATE RIDER SCHEDULE EPR-2
CLASSIFIED SERVICE
PURCHASE RATES FOR QUALIFIED FACILITIES
100 KW OR LESS FOR PARTIAL REQUIREMENTS

AVAILABILITY

This rate rider schedule is available in all territory served by the Company.

APPLICATION

This rate rider schedule is applicable to customers served by a retail rate schedule with metered kWh usage with a cogeneration or small power production facility with a nameplate continuous AC output power rating of 100 kW or less, where the facility's generator(s) and load are located at the same premise, and that otherwise meet qualifying status pursuant to Arizona Corporation Commission's Decision No. 52345 on cogeneration and small power production facilities. Applicable only to Qualifying Facilities electing to configure their systems as to require partial requirements service from the Company in order to meet their electric requirements.

At the Company's discretion, the monthly purchase rates in this schedule may also be used as a basis to purchase energy from a Qualifying Facility (QF) that is not configured for partial requirements service and/or is greater than 100 kW. The terms for such purchase shall be provided in a contract to be approved by the Commission.

Participation under this schedule is subject to the availability of required metering equipment compatible with the customer's retail rate schedule and electrical service configuration. All provisions of the customer's retail rate schedule will continue to apply except as noted below.

NEW AND EXISTING RESIDENTIAL SOLAR CUSTOMERS

An Existing Residential Solar Customer is one that has (1) interconnected their QF with APS prior to 2013 or (2) otherwise has submitted to APS an application for interconnection along with a signed contract with a QF installer prior to October 15, 2013 and (2) completed the interconnection within 180 days thereafter. Such designation shall only apply to the initial homeowner meeting these criteria and shall not be transferred to subsequent homeowners.

A New Residential Solar Customer is any other residential customer that installs a QF or purchases a home with an existing QF and does not meet these criteria.

An Existing Residential Solar Customer may use Rate Rider Schedule EPR-2 in conjunction with any retail rate that is generally accommodated for partial requirements service until April 15, 2034. After that time, this rate rider may only be used in conjunction with Rate Schedule ECT-2, or successor rate.

A New Residential Solar Customer may only use Rate Rider Schedule EPR-2 in conjunction with Rate Schedule ECT-2, or successor rate.

TYPE OF SERVICE

Electric sales to the Company must be single or three phase, 60 Hertz, at one standard voltage as may be selected by the customer (subject to availability at the premises). The Qualifying Facility will have the option to sell energy to the Company at a voltage level different than that for purchases from the Company; however, the Qualifying Facility will be responsible for all incremental costs incurred to accommodate such an arrangement.

SALES TO THE CUSTOMER

Power sales and special services supplied by the Company to the customer in order to meet its supplemental or interruptible electric requirements will be priced at the customer's retail rate schedule.

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RATE RIDER SCHEDULE EPR-2
CLASSIFIED SERVICE
PURCHASE RATES FOR QUALIFIED FACILITIES
100 KW OR LESS FOR PARTIAL REQUIREMENTS

PURCHASE OF EXCESS GENERATION

The Company shall issue a credit on the customer's monthly bill for the monthly Excess Generation, based on the relevant monthly purchase rates, which are based on avoided energy costs and shall be updated annually. Purchase rates are provided for Firm Power and Non-Firm Power for the summer and winter billing cycles. Firm Power is only relevant to the summer billing cycles.

For customers served under a time-of-use retail rate schedule, purchase rates are provided for the relevant on-peak and off-peak hours. For residential customers served under a non-time-of-use rate, or a time-of-use rate not specified below, the monthly purchase rate and on-peak and off-peak hours will be based on the rate for customers served on a 12 p.m. to 7 p.m. on-peak rate. For non-residential customers served under a non-time-of-use rate or a time-of-use rate not specified below, the monthly purchase rate and on-peak and off-peak hours will be based on the rate for customers served on an 11 a.m. to 9 p.m. on-peak rate. Unless specified in this schedule, Excess Generation during a super-on-peak or shoulder-peak time period in a retail rate will be purchased at the on-peak purchase rate, while Excess Generation during a super-off-peak period will be purchased at the off-peak purchase rate.

~~Purchase of Excess Generation (Con't)~~

For customers served under a 9 a.m. to 9 p.m. on-peak time-of-use retail rate schedule:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1]	Off-Peak[2]	On-Peak[1]	Off-Peak[2]
Summer Billing Cycles (May - October)	2.956	2.765	3.608	2.887
Winter Billing Cycles (November - April)	2.823	2.701	2.823	2.701

[1] On-Peak Periods: 9 a.m. to 9 p.m., weekdays or as reflected in the customer's retail rate schedule
[2] Off-Peak Periods: All other hours

For customers served under a 12 p.m. to 7 p.m. on-peak time-of-use retail rate schedule:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1]	Off-Peak[2]	On-Peak[1]	Off-Peak[2]
Summer Billing Cycles (May - October)	3.016	2.787	4.159	2.885
Winter Billing Cycles (November - April)	2.869	2.713	2.869	2.713

[1] On-Peak Periods: 12 p.m. to 7 p.m., weekdays or as reflected in the customer's retail rate schedule

RATE RIDER SCHEDULE EPR-2
CLASSIFIED SERVICE
PURCHASE RATES FOR QUALIFIED FACILITIES
100 KW OR LESS FOR PARTIAL REQUIREMENTS

~~[2] Off-Peak Periods: All other hours~~

(Purchase of Excess Generation Con't)

For customers served under an 11 a.m. to 9 p.m. on-peak time-of-use rate schedule:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1]	Off-Peak[2]	On-Peak[1]	Off-Peak[2]
Summer Billing Cycles (May - October)	2.991	2.767	3.773	2.878
Winter Billing Cycles (November - April)	2.827	2.709	2.827	2.709

[1] On-Peak Periods: 11 a.m. to 9 p.m., weekdays or as reflected in the customer's retail rate schedule
[2] Off-Peak Periods: All other hours

CONTRACT PERIOD

As provided for in any Supply /Purchase Agreement.

DEFINITIONS

1. Partial Requirements Service: Electric service provided to a customer that has an interconnected generation system configuration whereby the output from its electric generator(s) first supplies its own electric requirements and any Excess Generation (over and above its own requirements at any point in time) is then provided to the Company. The Company supplies the customer's supplemental electric requirements (those not met by their own generation facilities). This configuration may also be referred to as the "parallel mode" of operation.

2. Qualifying Facility (QF): A cogeneration or small power production facility which meets the requirements under 18 CFR, Chapter I, Part 292, Subpart B of the Federal energy Regulatory Commission regulations.

3. Excess Generation: Equals the customer's generation (kWh) in excess of their load at any point in time as metered by the Company. Excess Generation is computed for on-peak and off-peak billing periods.

4. Special Service(s): The electric service(s) specified in this section that will be provided by the Company in addition to or in lieu of normal service(s).

5. Non-Firm Power: Electric power which is supplied by the Customer's generator at the Customer's option, where no firm guarantee is provided and the power can be interrupted by the Customer at any time.

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RATE RIDER SCHEDULE EPR-2
CLASSIFIED SERVICE
PURCHASE RATES FOR QUALIFIED FACILITIES
100 KW OR LESS FOR PARTIAL REQUIREMENTS

6. Firm Power: Power available, upon demand, at all times (except for forced outages) during the period covered by the Purchase Agreement from the customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

(Definitions Con't)

7. Time Periods: Mountain Standard Time shall be used in the application of this rate schedule. Because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, Schedule 2, Terms and Conditions for Energy Purchases from Qualified Cogeneration or Small Power Production Facilities, and the Company's Interconnection requirements for Distributed Generation. This schedule has provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer interconnection or Supply/Purchase agreement.

METERING

Customers served under this rate schedule will require a bi-directional meter that will register and accumulate the net electrical requirements of the customer. The bi-directional meter shall be provided at no additional cost to the customer. A bi-directional meter may not be required if the generating capacity of the Qualifying Facility is less than 20% of the customer's lowest billing demand over the12 months prior to requesting enrollment in Schedule EPR-2, or as otherwise determined by the Company through available information, or if the customer agrees that they do not intend to be compensated for any Excess Generation.

RATE RIDER SCHEDULE EPR-6 (NET METERING)
CLASSIFIED SERVICE
RATES FOR RENEWABLE RESOURCE FACILITIES FOR PARTIAL REQUIREMENTS

AVAILABILITY

This rate rider schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate rider schedule is applicable to customers served by a retail rate schedule with metered kWh usage with a Net Metering Facility that uses Renewable Resources, a fuel cell, or combined heat and power (CHP) to produce electricity. Definitions are pursuant to A.A.C. R14-2-2302. Participation under this schedule is subject to the availability of required metering equipment compatible with the customer's retail rate schedule and electrical service configuration. All provisions of the customer's retail rate schedule will continue to apply except as noted below.

NEW AND EXISTING RESIDENTIAL SOLAR CUSTOMERS

An Existing Residential Solar Customer is one that has (1) interconnected their Net Metering Facility with APS prior to 2013 or (2) otherwise has submitted to APS an application for interconnection along with a signed contract with an installer prior to October 15, 2013 and completed the interconnection within 180 days thereafter. Such designation shall only apply to the initial homeowner meeting these criteria and shall not be transferred to subsequent homeowners.

A New Residential Solar Customer is any other residential customer that installs a Net Metering Facility or purchases a home with an existing facility and does not meet these criteria.

An Existing Residential Solar Customer may use Rate Rider Schedule EPR-6 in conjunction with any retail rate that is generally accommodated for partial requirements service until April 15, 2034. After that time, this rate rider may only be used in conjunction with Rate Schedule ECT-2, or successor rate.

A New Residential Solar Customer may only use Rate Rider Schedule EPR-6 in conjunction with Rate Schedule ECT-2, or successor rate.

DEFINITIONS

1. Combined Heat and Power (CHP): 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.

2. Customer Supply: Energy (kWh) from a customer-owned Net Metering Facility that exceeds the customer's load at a point in time and is fed back into the Company's electric system, as metered by the Company.

3. Customer Purchase: Energy (kWh) that is provided from the Company to the customer to serve the load that is not being served by a customer-owned Net Metering Facility, as metered by the Company.

4. Excess Generation: Equals the Customer Supply (kWh) less the Customer Purchase (kWh) over a monthly billing period. For time-of-use rates the Excess Generation corresponding to the on-peak and off- peak periods is computed for on-peak and off-peak periods over the monthly billing period. (Not to be less than zero).

DEFINITIONS (Cont)

5. Fuel Cell: A device that converts the chemical energy of a fuel directly into electricity without intermediate combustion or thermal cycles. For purposes of this rate schedule, the source of the chemical reaction must be derived from Renewable Resources.

6. Net Metering Facility: A facility for the production of electricity that:

   a) Is operated by or on behalf of a Net Metering customer and is located on the net metering customer's premises and;
   b) Is intended primarily to provide part or all of the net metering customer's requirement for electricity at the single point of electrical service where the generator is installed and;
   c) Uses Renewable Resources, a fuel cell, or CHP to generate electricity and;
   d) Has a generating capacity less then or equal to 125% of the net metering customer's Total Connected Load (kW), or in the absence of customer load data, capacity less than or equal to the customer's electric service drop capacity and;
   e) Is interconnected with and can operate in parallel and in phase with the Company's existing distribution system.

~~DEFINITIONS (Cont)~~

7. Partial Requirements Service: Electric service provided to a customer that has an interconnected Net Metering Facility whereby the output from its electric generator(s) first supplies its own electric requirements and any excess energy (over and above its own requirements at any point in time) is then provided to the Company. The Company supplies the customer's supplemental electric requirements (those not met by their own generation facilities). This configuration may also be referred to as the "parallel mode" of operation.

8. Renewable Resources: Natural resources that can be replenished by natural processes, including biogas, biomass, geothermal, hydroelectric, solar or wind.

9. Non-Firm Power: Electric power which is supplied by the Customer's generator at the Customer's option, where no firm guarantee is provided and the power can be interrupted by the Customer at any time.

10. Firm Power: Power available, upon demand, at all times (except for forced outages) during the period covered by the Purchase Agreement from the customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources. Determination of Firm Power will be in accordance with Rate Schedule EPR-2.

11. Time Periods: Mountain Standard Time shall be used in the application of this rate schedule. Because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods. On-peak and off-peak time periods will be determined by the customer's retail rate schedule.

RATE RIDER SCHEDULE EPR-6 (NET METERING) CLASSIFIED SERVICE RATES FOR RENEWABLE RESOURCE FACILITIES FOR PARTIAL REQUIREMENTS

12. Total Connected Load: The maximum potential demand (kW) measured or calculated at the electrical service entrance section serving the Net Metering Facility.

TYPE OF SERVICE

Electric sales to the Company must be single phase or three phase, 60 Hertz, at one standard voltage as may be selected by customer (subject to availability at the premises).

BILLING

A. During the billing period for:

1. Customer Purchases in excess of Customer Supply:

   Company shall bill the customer for the net kWh supplied by the Company in accordance with the customer's retail rate schedule.

2. Customer Supply in excess of Customer Purchases (Excess Generation):

   Company shall credit the customer the Excess Generation kWh in subsequent billing periods.

~~BILLING (Cont)~~

B. For customers taking service under time-of-use rates, Customer Supply and Customer Purchases will be segmented by on-peak and off-peak periods. Excess Generation kWh credits will be applied to the time-of-use periods in which the kWh were generated by the customer. If necessary, a super off-peak period may be combined with an off-peak period for netting purposes. Likewise, a peak period may be combined with a super-peak or shoulder period for netting purposes. In either case, netting shall occur from the lowest price period first.

C. Basic Service Charges and Demand charges (either metered or contract) will continue to apply in full.

D. For the last billing period of each calendar year, or for the last billing period at the time the customer discontinues taking service under this rate rider scheduler:

   The Company shall issue a billing credit to the customer for any remaining Excess Generation balance. In the event the customer's electric service is terminated, after applying a billing credit for any Excess Generation up to the amount the customers owes the Company, the Company shall issue a check for the remaining value of the Excess Generation balance. The credit will be determined by the Annual Purchase Rates for Excess Generation which are based on the Company's avoided costs and updated annually.

   The annual billing credit for customers served under a time-of-use rate shall be based on the on-peak and off-peak Annual Purchase Rates applied to the remaining kWh bank balance for the on-peak and off-peak periods. The billing credit for customers served under a non-time-of-use rate shall be based on the total Annual Purchase Rate applied to the total remaining kWh bank balance.

   Annual Purchase Rates for Excess Generation (¢/kWh)

Non-Firm Power	Firm Power

RATE RIDER SCHEDULE EPR-6 (NET METERING)
CLASSIFIED SERVICE
RATES FOR RENEWABLE RESOURCE FACILITIES FOR PARTIAL REQUIREMENTS

	On-peak	Off-peak	Total	On-peak	Off-peak	Total
Time-of-use rates	2.890	2.733		3.220	2.795	
Other rates			2.789			2.947

DETERMINATION OF TOTAL CONNECTED LOAD

The generating capacity (kW) of the Net Metering Facility shall be determined by the Company to be less than or equal to 125% of the customer's Total Connected Load (kW) if it is:

1. Less than or equal to 30 kW or

2. Less than or equal to 125% times the customer's maximum metered demand prior to installing the Net Metering Facility, using available billing information at the time a customer requests enrollment in Schedule EPR-6. If metered demand information is not available, it may be estimated by multiplying monthly metered energy times a conversion factor of 0.00342 (kW per kWh), which is derived from a 40% load factor and 730 hours per month, or

3. Less than or equal to 125% times the maximum demand (kW) specified in an electric supply agreement, or

~~DETERMINATION OF TOTAL CONNECTED LOAD (Cont)~~

4. Less than or equal to 125% times the Total Connected Load (kW), which shall be determined from certified detailed load information supplied by the customer and approved by the Company, or

5. Less than or equal to the customer's service run capacity as determined by APS, prior to any upgrade to accommodate the customer's Net Metering Facility. Condition 5 shall only apply if metered load and Total Connected Load (kW) information is not able to be calculated.

CONTRACT PERIOD

Any applicable contract period(s) will be set forth in an Agreement between the customer and the Company.

METERING

Customers served under this rate schedule will require a bi-directional meter that will register and accumulate the net electrical requirements of the customer. The bi-directional meter shall be provided at no additional cost to the customer. A bi-directional meter may not be required if the generating capacity of the Net Metering Facility is less than 20% of the customer's lowest billing demand over the 12 months prior to requesting enrollment in Schedule EPR-6, or as otherwise determined by the Company through available information, or if the customer agrees that they do not intend to net any Excess Generation on their monthly bill.

TERMS AND CONDITIONS

RATE RIDER SCHEDULE EPR-6 (NET METERING)
CLASSIFIED SERVICE
RATES FOR RENEWABLE RESOURCE FACILITIES
FOR PARTIAL REQUIREMENTS

Service under this rate schedule is subject to the Company's Schedule 1 Terms and Conditions for Standard Offer and Direct Access Services, Schedule 2 Terms and Conditions for Energy Purchases from Qualified Cogeneration or Small Power Production Facilities, Schedule 3 Conditions Governing Extensions of Electrical Distribution Lines and Services, and the Company's Interconnection Requirements for Distributed Generation.

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service, except as stated below, required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatt/kilowatthour meter.

This schedule is not applicable to breakdown, standby, supplemental or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services) and is required for motors of an individual rated capacity of 7-1/2 HP or more.

RATES

The customer's bill shall be computed at the following rates, plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $ 0.556 per day

Optional Basic Service Charge for Opting Out of Adjustment Schedule LFCR:

Total Monthly Metered kWh	Basic Service Charge
0 to 400 kWh	$0.576 per day
401 to 800 kWh	$0.596 per day
801 to 2000 kWh	$0.648 per day
2001 kWh and greater	$0.773 per day

This charge will not be available until the first reset of Adjustment Schedule LFCR, which will be on or about March 1, 2013.

Demand Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$13.500 per On-Peak kW	$9.300 per On-Peak kW

RATES (cont)

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
\$0.08867 per kWh during On-Peak hours, plus \$0.04417 per kWh during Off-Peak hours	\$0.05747 per kWh during On-Peak hours, plus \$0.04107 per kWh during Off-Peak hours

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Components

Customer Accounts Charge: \$ 0.238 per day

Optional Customer Accounts Charge for Opting Out of Adjustment Schedule LFCR:

Total Monthly Metered kWh	Customer Accounts Charge
0 to 400 kWh	\$0.258 per day
401 to 800 kWh	\$0.278 per day
801 to 2000 kWh	\$0.330 per day
2001 kWh and greater	\$0.455 per day

Revenue Cycle Service Charges:

Metering	\$ 0.186	per day
Meter Reading	\$ 0.062	per day
Billing	\$ 0.070	per day
System Benefits Charge:	\$ 0.00297	per kWh
Transmission Charge:	\$ 0.00520	per kWh

Delivery Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
\$4.500 per On-Peak kW, plus \$0.01400 per kWh	\$2.400 per On-Peak kW, plus \$0.01590 per kWh

RATES (cont)

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
\$9.000 per On-Peak kW, plus \$0.06650 per kWh during On-Peak hours, plus \$0.02200 per kWh during Off-Peak hours	\$6.900 per On-Peak kW, plus \$0.03340 per kWh during On-Peak hours, plus \$0.01700 per kWh during Off-Peak hours

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Customer Accounts Charge, the System Benefits Charge, and the Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

TIME PERIODS

The On-Peak time period for this rate schedule is 12 noon to 7 p.m. Monday through Friday excluding the holidays listed below. All hours not included in the On-Peak time period shall be Off-Peak hours. The following holidays are Off-Peak: New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25). When any holiday listed above falls on a Saturday, the preceding Friday will be recognized as an

TIME PERIODS

off-peak period. When any holiday listed above falls on a Sunday, the following Monday will be recognized as an off-peak period.

Mountain Standard Time shall be used in the application of this rate schedule.

DETERMINATION OF KW

For billing purposes, the kW used in this rate schedule shall be based on the average kW supplied during the 60-minute period of maximum use during the customer's On-Peak hours, as determined from readings of the Company's meter.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 and 73183.

ADJUSTMENTS (cont)

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744.

4. The bill is subject to the Environmental Improvement Surcharge as set forth in the Company's Adjustment Schedule EIS pursuant to Arizona Corporation Commission Decision No. 69663 and Arizona Corporation Commission Decision No. 73183.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

6. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

7. The bill is subject to the Lost Fixed Cost Recovery mechanism as set forth in the Company's Adjustment Schedule LFCR pursuant to Arizona Corporation Commission Decision No. 73183, unless the customer opts out from this adjustment and is subject to the Optional Basic Service Charge.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE RIDER SCHEDULE EPR-2
CLASSIFIED SERVICE
PURCHASE RATES FOR QUALIFIED FACILITIES 100 KW OR LESS FOR PARTIAL REQUIREMENTS

AVAILABILITY

This rate rider schedule is available in all territory served by the Company.

APPLICATION

This rate rider schedule is applicable to customers served by a retail rate schedule with metered kWh usage with a cogeneration or small power production facility with a nameplate continuous AC output power rating of 100 kW or less, where the facility's generator(s) and load are located at the same premise, and that otherwise meet qualifying status pursuant to Arizona Corporation Commission's Decision No. 52345 on cogeneration and small power production facilities. Applicable only to Qualifying Facilities (QF) electing to configure their systems as to require partial requirements service from the Company in order to meet their electric requirements.

At the Company's discretion, the monthly purchase rates in this schedule may also be used as a basis to purchase energy from a Qualifying Facility that is not configured for partial requirements service and/or is greater than 100 kW. The terms for such purchase shall be provided in a contract to be approved by the Commission.

Participation under this schedule is subject to the availability of required metering equipment compatible with the customer's retail rate schedule and electrical service configuration. All provisions of the customer's retail rate schedule will continue to apply except as noted below.

NEW AND EXISTING RESIDENTIAL SOLAR CUSTOMERS

An Existing Residential Solar Customer is one that has (1) interconnected their QF with APS prior to 2013 or (2) otherwise has submitted to APS an application for interconnection along with a signed contract with a QF installer prior to October 15, 2013 and completed the interconnection within 180 days thereafter. Such designation shall only apply to the initial homeowner meeting these criteria and shall not be transferred to subsequent homeowners.

A New Residential Solar Customer is any other residential customer that installs a QF or purchases a home with an existing QF and does not meet these criteria.

An Existing Residential Solar Customer may subscribe to Rate Rider Schedule EPR-2 in conjunction with any retail rate that is generally accommodated for partial requirements service until April 15, 2034. After that time, they must take service under Rate Rider Schedule EPR-7, or successor rate.

A New Residential Solar Customer is not eligible for Rate Rider Schedule EPR-2; they must take service under Rate Rider Schedule EPR-7, or successor rate.

TYPE OF SERVICE

Electric sales to the Company must be single or three phase, 60 Hertz, at one standard voltage as may be selected by the customer (subject to availability at the premises). The Qualifying Facility will have the option to sell energy to the Company at a voltage level different than that for purchases from the Company; however, the Qualifying Facility will be responsible for all incremental costs incurred to accommodate such an arrangement.

SALES TO THE CUSTOMER

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RATE RIDER SCHEDULE EPR-2
CLASSIFIED SERVICE
PURCHASE RATES FOR QUALIFIED FACILITIES
100 KW OR LESS FOR PARTIAL REQUIREMENTS

Power sales and special services supplied by the Company to the customer in order to meet its supplemental or interruptible electric requirements will be priced at the customer's- retail rate schedule.

PURCHASE OF EXCESS GENERATION

The Company shall issue a credit on the customer's monthly bill for the monthly Excess Generation, based on the relevant monthly purchase rates, which are based on avoided energy costs and shall be updated annually. Purchase rates are provided for Firm Power and Non-Firm Power for the summer and winter billing cycles. Firm Power is only relevant to the summer billing cycles.

For customers served under a time-of-use retail rate schedule, purchase rates are provided for the relevant on-peak and off-peak hours. For residential customers served under a non-time-of-use rate, or a time-of-use rate not specified below, the monthly purchase rate and on-peak and off-peak hours will be based on the rate for customers served on a 12 p.m. to 7 p.m. on-peak rate. For non-residential customers served under a non-time-of-use rate or a time-of-use rate not specified below, the monthly purchase rate and on-peak and off-peak hours will be based on the rate for customers served on an 11 a.m. to 9 p.m. on-peak rate. Unless specified in this schedule, Excess Generation during a super-on-peak or shoulder-peak time period in a retail rate will be purchased at the on-peak purchase rate, while Excess Generation during a super-off-peak period will be purchased at the off-peak purchase rate.

~~Purchase of Excess Generation (Con't)~~

For customers served under a 9 a.m. to 9 p.m. on-peak time-of-use retail rate schedule:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1]	Off-Peak[2]	On-Peak[1]	Off-Peak[2]
Summer Billing Cycles (May - October)	2.956	2.765	3.608	2.887
Winter Billing Cycles (November - April)	2.823	2.701	2.823	2.701

[1] On-Peak Periods: 9 a.m. to 9 p.m., weekdays or as reflected in the customer's retail rate schedule
[2] Off-Peak Periods: All other hours

For customers served under a 12 p.m. to 7 p.m. on-peak time-of-use retail rate schedule:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1]	Off-Peak[2]	On-Peak[1]	Off-Peak[2]
Summer Billing Cycles (May - October)	3.016	2.787	4.159	2.885
Winter Billing Cycles (November - April)	2.869	2.713	2.869	2.713

RATE RIDER SCHEDULE EPR-2
CLASSIFIED SERVICE
PURCHASE RATES FOR QUALIFIED FACILITIES
100 KW OR LESS FOR PARTIAL REQUIREMENTS

[1] On-Peak Periods: 12 p.m. to 7 p.m., weekdays or as reflected in the customer's retail rate schedule
[2] Off-Peak Periods: All other hours

(Purchase of Excess Generation Con't)

For customers served under an 11 a.m. to 9 p.m. on-peak time-of-use rate schedule:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1]	Off-Peak[2]	On-Peak[1]	Off-Peak[2]
Summer Billing Cycles (May - October)	2.991	2.767	3.773	2.878
Winter Billing Cycles (November - April)	2.827	2.709	2.827	2.709

[1] On-Peak Periods: 11 a.m. to 9 p.m., weekdays or as reflected in the customer's retail rate schedule
[2] Off-Peak Periods: All other hours

CONTRACT PERIOD

As provided for in any Supply /Purchase Agreement.

DEFINITIONS

1. Partial Requirements Service: Electric service provided to a customer that has an interconnected generation system configuration whereby the output from its electric generator(s) first supplies its own electric requirements and any Excess Generation (over and above its own requirements at any point in time) is then provided to the Company. The Company supplies the customer's supplemental electric requirements (those not met by their own generation facilities). This configuration may also be referred to as the "parallel mode" of operation.

2. Qualifying Facility (QF): A cogeneration or small power production facility which meets the requirements under 18 CFR, Chapter I, Part 292, Subpart B of the Federal energy Regulatory Commission regulations.

3. Excess Generation: Equals the customer's generation (kWh) in excess of their load at any point in time as metered by the Company. Excess Generation is computed for on-peak and off-peak billing periods.

4. Special Service(s): The electric service(s) specified in this section that will be provided by the Company in addition to or in lieu of normal service(s).

5. Non-Firm Power: Electric power which is supplied by the Customer's generator at the Customer's option, where no firm guarantee is provided and the power can be interrupted by the Customer at any time.

RATE RIDER SCHEDULE EPR-2
CLASSIFIED SERVICE
PURCHASE RATES FOR QUALIFIED FACILITIES
100 KW OR LESS FOR PARTIAL REQUIREMENTS

6. Firm Power: Power available, upon demand, at all times (except for forced outages) during the period covered by the Purchase Agreement from the customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

(Definitions Con't)

7. Time Periods: Mountain Standard Time shall be used in the application of this rate schedule. Because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, Schedule 2, Terms and Conditions for Energy Purchases from Qualified Cogeneration or Small Power Production Facilities, and the Company's Interconnection requirements for Distributed Generation. This schedule has provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer interconnection or Supply/Purchase agreement.

METERING

Customers served under this rate schedule will require a bi-directional meter that will register and accumulate the net electrical requirements of the customer. The bi-directional meter shall be provided at no additional cost to the customer. A bi-directional meter may not be required if the generating capacity of the Qualifying Facility is less than 20% of the customer's lowest billing demand over the12 months prior to requesting enrollment in Schedule EPR-2, or as otherwise determined by the Company through available information, or if the customer agrees that they do not intend to be compensated for any Excess Generation.

RATE RIDER SCHEDULE EPR-6 (NET METERING) CLASSIFIED SERVICE RATES FOR RENEWABLE RESOURCE FACILITIES FOR PARTIAL REQUIREMENTS

AVAILABILITY

This rate rider schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate rider schedule is applicable to customers served by a retail rate schedule with metered kWh usage with a Net Metering Facility that uses Renewable Resources, a fuel cell, or combined heat and power (CHP) to produce electricity. Definitions are pursuant to A.A.C. R14-2-2302. Participation under this schedule is subject to the availability of required metering equipment compatible with the customer's retail rate schedule and electrical service configuration. All provisions of the customer's retail rate schedule will continue to apply except as noted below.

NEW AND EXISTING RESIDENTIAL SOLAR CUSTOMERS

An Existing Residential Solar Customer is one that has (1) interconnected their Net Metering Facility with APS prior to 2013 or (2) otherwise has submitted to APS an application for interconnection along with a signed contract with an installer prior to October 15, 2013 and completed the interconnection within 180 days thereafter. Such designation shall only apply to the initial homeowner meeting these criteria and shall not be transferred to subsequent homeowners.

A New Residential Solar Customer is any other residential customer that installs a Net Metering Facility or purchases a home with an existing facility and does not meet these criteria.

An Existing Residential Solar Customer may subscribe to Rate Rider Schedule EPR-6 in conjunction with any retail rate that is generally accommodated for partial requirements service until April 15, 2034. After that time, they must take service under Rate Rider Schedule EPR-7, or successor rate.

A New Residential Solar Customer is not eligible for Rate Rider Schedule EPR-6; they must take service under Rate Rider Schedule EPR-7, or successor rate.

DEFINITIONS

1. Combined Heat and Power (CHP): 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.

2. Customer Supply: Energy (kWh) from a customer-owned Net Metering Facility that exceeds the customer's load at a point in time and is fed back into the Company's electric system, as metered by the Company.

3. Customer Purchase: Energy (kWh) that is provided from the Company to the customer to serve the load that is not being served by a customer-owned Net Metering Facility, as metered by the Company.

4. Excess Generation: Equals the Customer Supply (kWh) less the Customer Purchase (kWh) over a monthly billing period. For time-of-use rates the Excess Generation corresponding to the on-peak and off- peak periods is computed for on-peak and off-peak periods over the monthly billing period. (Not to be less than zero).

(Definitions Con't)

5. Fuel Cell: A device that converts the chemical energy of a fuel directly into electricity without intermediate combustion or thermal cycles. For purposes of this rate schedule, the source of the chemical reaction must be derived from Renewable Resources.

6. Net Metering Facility: A facility for the production of electricity that:

   a) Is operated by or on behalf of a Net Metering customer and is located on the net metering customer's premises and;
   b) Is intended primarily to provide part or all of the net metering customer's requirement for electricity at the single point of electrical service where the generator is installed and;
   c) Uses Renewable Resources, a fuel cell, or CHP to generate electricity and;
   d) Has a generating capacity less then or equal to 125% of the net metering customer's Total Connected Load (kW), or in the absence of customer load data, capacity less than or equal to the customer's electric service drop capacity and;
   e) Is interconnected with and can operate in parallel and in phase with the Company's existing distribution system.

~~DEFINITIONS (Cont)~~

7. Partial Requirements Service: Electric service provided to a customer that has an interconnected Net Metering Facility whereby the output from its electric generator(s) first supplies its own electric requirements and any excess energy (over and above its own requirements at any point in time) is then provided to the Company. The Company supplies the customer's supplemental electric requirements (those not met by their own generation facilities). This configuration may also be referred to as the "parallel mode" of operation.

8. Renewable Resources: Natural resources that can be replenished by natural processes, including biogas, biomass, geothermal, hydroelectric, solar or wind.

9. Non-Firm Power: Electric power which is supplied by the Customer's generator at the Customer's option, where no firm guarantee is provided and the power can be interrupted by the Customer at any time.

10. Firm Power: Power available, upon demand, at all times (except for forced outages) during the period covered by the Purchase Agreement from the customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources. Determination of Firm Power will be in accordance with Rate Schedule EPR-2.

11. Time Periods: Mountain Standard Time shall be used in the application of this rate schedule. Because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods. On-peak and off-peak time periods will be determined by the customer's retail rate schedule.

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RATE RIDER SCHEDULE EPR-6 (NET METERING)
CLASSIFIED SERVICE
RATES FOR RENEWABLE RESOURCE FACILITIES FOR PARTIAL REQUIREMENTS

12. Total Connected Load: The maximum potential demand (kW) measured or calculated at the electrical service entrance section serving the Net Metering Facility.

TYPE OF SERVICE

Electric sales to the Company must be single phase or three phase, 60 Hertz, at one standard voltage as may be selected by customer (subject to availability at the premises).

BILLING

A. During the billing period for:

1. Customer Purchases in excess of Customer Supply:

   Company shall bill the customer for the net kWh supplied by the Company in accordance with the customer's retail rate schedule.

2. Customer Supply in excess of Customer Purchases (Excess Generation):

   Company shall credit the customer the Excess Generation kWh in subsequent billing periods.

~~BILLING (Cont)~~

B. For customers taking service under time-of-use rates, Customer Supply and Customer Purchases will be segmented by on-peak and off-peak periods. Excess Generation kWh credits will be applied to the time-of-use periods in which the kWh were generated by the customer. If necessary, a super off-peak period may be combined with an off-peak period for netting purposes. Likewise, a peak period may be combined with a super-peak or shoulder period for netting purposes. In either case, netting shall occur from the lowest price period first.

C. Basic Service Charges and Demand charges (either metered or contract) will continue to apply in full.

D. For the last billing period of each calendar year, or for the last billing period at the time the customer discontinues taking service under this rate rider scheduler:

   The Company shall issue a billing credit to the customer for any remaining Excess Generation balance. In the event the customer's electric service is terminated, after applying a billing credit for any Excess Generation up to the amount the customers owes the Company, the Company shall issue a check for the remaining value of the Excess Generation balance. The credit will be determined by the Annual Purchase Rates for Excess Generation which are based on the Company's avoided costs and updated annually.

   The annual billing credit for customers served under a time-of-use rate shall be based on the on-peak and off-peak Annual Purchase Rates applied to the remaining kWh bank balance for the on-peak and off-peak periods. The billing credit for customers served under a non-time-of-use rate shall be based on the total Annual Purchase Rate applied to the total remaining kWh bank balance.

   Annual Purchase Rates for Excess Generation (¢/kWh)

RATE RIDER SCHEDULE EPR-6 (NET METERING)
CLASSIFIED SERVICE
RATES FOR RENEWABLE RESOURCE FACILITIES
FOR PARTIAL REQUIREMENTS

	Non-Firm Power			Firm Power		
	On-peak	Off-peak	Total	On-peak	Off-peak	Total
Time-of-use rates	2.890	2.733		3.220	2.795	
Other rates			2.789			2.947

DETERMINATION OF TOTAL CONNECTED LOAD

The generating capacity (kW) of the Net Metering Facility shall be determined by the Company to be less than or equal to 125% of the customer's Total Connected Load (kW) if it is:

1. Less than or equal to 30 kW or

2. Less than or equal to 125% times the customer's maximum metered demand prior to installing the Net Metering Facility, using available billing information at the time a customer requests enrollment in Schedule EPR-6. If metered demand information is not available, it may be estimated by multiplying monthly metered energy times a conversion factor of 0.00342 (kW per kWh), which is derived from a 40% load factor and 730 hours per month, or

3. Less than or equal to 125% times the maximum demand (kW) specified in an electric supply agreement, or

~~DETERMINATION OF TOTAL CONNECTED LOAD (Cont)~~

4. Less than or equal to 125% times the Total Connected Load (kW), which shall be determined from certified detailed load information supplied by the customer and approved by the Company, or

5. Less than or equal to the customer's service run capacity as determined by APS, prior to any upgrade to accommodate the customer's Net Metering Facility. Condition 5 shall only apply if metered load and Total Connected Load (kW) information is not able to be calculated.

CONTRACT PERIOD

Any applicable contract period(s) will be set forth in an Agreement between the customer and the Company.

METERING

Customers served under this rate schedule will require a bi-directional meter that will register and accumulate the net electrical requirements of the customer. The bi-directional meter shall be provided at no additional cost to the customer. A bi-directional meter may not be required if the generating capacity of the Net Metering Facility is less than 20% of the customer's lowest billing demand over the 12 months prior to requesting enrollment in Schedule EPR-6, or as otherwise determined by the Company through available information, or if the customer agrees that they do not intend to net any Excess Generation on their monthly bill.

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RATE RIDER SCHEDULE EPR-6 (NET METERING) CLASSIFIED SERVICE RATES FOR RENEWABLE RESOURCE FACILITIES FOR PARTIAL REQUIREMENTS

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1 Terms and Conditions for Standard Offer and Direct Access Services, Schedule 2 Terms and Conditions for Energy Purchases from Qualified Cogeneration or Small Power Production Facilities, Schedule 3 Conditions Governing Extensions of Electrical Distribution Lines and Services, and the Company's Interconnection Requirements for Distributed Generation.

RATE RIDER SCHEDULE EPR-7
CLASSIFIED SERVICE
BILL CREDIT RATE FOR CUSTOMER GENERATION

AVAILABILITY

This rate rider schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate rider schedule is available to residential customers with metered kWh usage who install a generation facility, such as solar, wind, or other generation types, on their premises. This rider may be used in conjunction with all other retail rates and riders that are accommodated with the Company's metering and billing system. All provisions of the customer's retail rate schedule are applicable in addition to the charges and provisions of this rate rider schedule.

All residential customers with generation facilities that do not qualify for service under Rate Rider Schedules EPR-2 or EPR-6 must be served under this rate rider schedule.

CUSTOMER GENERATION

The customer's generation facility must be interconnected to the Company's grid following the relevant practices and procedures.

Renewable Generation is a facility that uses renewable fuel, such as solar, wind, biomas, biogas, geothermal, a fuel, or other renewable generation types as provided in A.A.C. R14-2-2302. Standard Generation shall be all other generation facilities.

The generation facility shall be configured such that the total generation output shall be credited by APS at the relevant credit rate; the generation facility shall not serve the customer's electrical usage at any point in time or be netted against metered energy purchases from APS.

CREDIT RATES

The bill credit will be determined by multiplying the total metered kWh output of the customer's generation over the monthly billing period times the applicable generation credit rate.

The credit rate for Standard Generation shall equal the annual purchase rate for Rate Rider Schedule EPR-6 for total non-firm power, which shall be updated annually. The credit rate for Renewable Generation is provided below and shall be updated annually.

Standard Generation	0.02789	($/kWh)
Renewable Generation	0.04068	($/kWh)

METERING

Customers served under this rate schedule will require a production meter on their generator facility, which will be provided by the Company at no additional charge.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1 Terms and Conditions for Standard Offer and Direct Access Services, Schedule 2 Terms and Conditions for Energy Purchases from Qualified Cogeneration or Small Power Production Facilities, Schedule 3 Conditions Governing Extensions of Electrical Distribution Lines and Services, and the Company's Interconnection Requirements for Distributed Generation.

EXHIBIT 4

Arizona Public Service Company

Distributed Energy and Net Metering Technical Conference

Facilitator's Report

July 8, 2013

nFRONT CONSULTING

Power Industry Planners • Analysts • Advisors

July 8, 2013

Mr. Gregory Bernosky
Manager, APS Renewable Energy Program
400 North 5th Street
Phoenix AZ 85004

Dear Mr. Bernosky:

Subject: **Facilitator's Report for the Distributed Energy and Net Metering Technical Conference**

Please find herein the Facilitator's Report for the 2013 Distributed Energy and Net Metering Technical Conference (Technical Conference) conducted February 21, 2013 through May 28, 2013 in Phoenix, Arizona. The Technical Conference was conducted to comply with the Arizona Corporation Commission order "...that APS shall conduct a multi-session technical conference to evaluate the costs and benefits of Distributed Renewable Energy and Net Metering" as part of the APS Renewable Energy Standard 2013 Implementation Plan filing. The following report chronicles my understanding of the major events and summarizes significant observations of the Technical Conference.

Should you have any questions or need any additional information, please do not hesitate to contact me at your convenience.

Respectfully submitted,

Robert L. Davis
Lead Facilitator for the
Distributed Energy and Net Metering Technical Conference
Principal and Executive Consultant
nFront Consulting LLC

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EXECUTIVE SUMMARY

The Distributed Energy and Net Metering Technical Conference (Technical Conference) described herein was conducted to comply with the Arizona Corporation Commission (ACC) decision 73636, which ordered "that APS shall conduct a multi-session technical conference to evaluate the costs and benefits of Distributed Renewable Energy and Net Metering."

Over the course of the Technical Conference, participants engaged in a variety of technical discussions regarding the evaluation of costs and benefits of distributed energy (DE) and net metering. Conference participants encompassed a broad spectrum of ideologies and business interests, and included stakeholders from multiple facets of the solar industry, electricity consumer groups, regulatory interests, and electric utilities, including APS. Content experts were also enlisted by the conference Facilitator, stakeholders and APS to further educate conference participants and enhance the Technical Conference discussions through reports and presentations. During the Technical Conference, studies of costs and benefits of DE and net metering were presented by the stakeholders and APS.

The following report, prepared by the Facilitator for the Technical Conference, summarizes the proceedings of the Technical Conference and major observations that, in the opinion of the Facilitator, represent the most significant events and outcomes of the conference. Inasmuch as the report provides a summary of the Technical Conference as observed by the Facilitator, specific opinions of APS and other stakeholders may be different from those contained herein.

TECHNICAL CONFERENCE TOPICS

The following list provides a high-level summary of topics presented and discussed during the Technical Conference. Additional information on the Technical Conference is presented in the following sections of this report and on the website for the Technical Conference, www.solarfuturearizona.com.

- DE and net metering activities throughout the United States
- Assumptions and methodology used in the SAIC study of DE value
- Overview of processes used in electric utility retail ratemaking
- Review of APS rates and the potential for solar DE to shift cost responsibility to non-participating customers
- Stakeholder study of costs and benefits of net metering
- Overview of traditional utility avoided cost computations
- Review of APS computation of avoided costs from DE
- Discussion of fuel and energy subsidies
- Introduction to alternative DE evaluation models
- Assumptions, methodology, and results of the SAIC update of the 2009 R.W.Beck Study of DE value (SAIC study)
- Stakeholder study of DE costs and benefits for APS

- Trends in DE and net metering programs and regulations for other utilities and jurisdictions
- Discussion of potential APS proposals
- Summary of stakeholder perspectives on DE and net metering costs and benefits

PERSPECTIVES ON COSTS AND BENEFITS

Beyond the broader technical presentations and discussions on implementation and regulation of DE and net metering, a central component of the Technical Conference was a discussion on how DE and net metering should be evaluated when developing utility programs and setting rates, and specifically, what costs and benefits should be included when performing such evaluations. Two approaches were used during the Technical Conference to distinguish areas of agreement and disagreement between stakeholders (including APS). The first, an exercise to achieve alignment between stakeholders on critical subjects was utilized through Workshop II. The second approach, begun from initiatives of stakeholders during Workshop I, documented the diverse perspectives of different stakeholder groups on the costs and benefits to include in evaluations of DE and net metering.

Alignment

Alignment of stakeholder views were generally achieved on subjects of desired outcomes for the Technical Conference, DE and net metering program implementation, and clear statements of facts regarding DE and net metering technologies, but limited alignment was achieved on the technical approach and assumptions to use when evaluating DE and net metering. Alignments specific to the approach and assumptions are listed below. Additional discussion of alignments can be found in the following workshop summaries and in the Appendix.

- DE rate impacts can occur through behind the meter rate offsets (self-supply) as well as net metering bill credits.
- DE impacts both costs to serve and revenues collected.
- DE customers have unique load profiles, benefits and costs.

Cost-Benefit Matrix

Documentation of diverse stakeholder perspectives was achieved over several workshops through the development of the Cost-Benefit Matrix. Development of the Cost-Benefit Matrix is described more fully below in the workshop summaries, and a copy of the final version of the matrix is contained in the Appendix to this report. The Cost-Benefit Matrix represents a list of potential costs and benefits for consideration when evaluating DE and net metering.

In the most general sense, all stakeholders agree that an evaluation of DE or net metering should consider direct cost impacts on the electric utility (costs incurred and costs avoided). Conversely, stakeholders disagree on whether to include costs and benefits commonly characterized as societal benefits or externalities. Solar industry and environmental stakeholders recommend including societal benefits in DE and net metering evaluations, while stakeholders for electric utilities and large electricity consumers recommend excluding such benefits. Moreover, even where there is general agreement on costs and benefits that should be included in an evaluation of DE or net metering, there are differences of opinion on how such costs should be calculated. For instance, solar industry and environmental stakeholders generally recommend computing costs and benefits using long-term levelized or present-value computations, while stakeholders for electric utilities and large electricity consumers recommend computation of costs and benefits using historical test year methods consistent with approved rate-setting practices in Arizona.

An overview of significant findings derived from development of the Cost-Benefit Matrix is provided below. The Cost-Benefit Matrix in the Appendix provides additional information on stakeholder perspectives and definitions of specific costs and benefits categories.

Categories with Limited Agreement

All stakeholders generally agree that of DE and net metering evaluation should incorporate impacts for the following utility costs:

- Fuel and purchased power
- Variable operations and maintenance
- Environmental compliance
- Avoided generation capacity
- Fixed operation and maintenance for avoided generation capacity
- Electric system losses
- Avoided transmission and distribution (T&D) investments
- Integration costs
- Utility administration costs

Categories with Methodological Differences

Stakeholder perspectives outlined in the Cost-Benefit Matrix highlight significant differences in methodologies recommended for computation of costs and benefits of DE and net metering. Differences typically involve whether avoided utility costs should be computed for the marginal or market cost of generic facilities (view of solar industry stakeholders) or for distinctly identified facilities, including specific facility sizes and timing (view of electric utilities and large consumer stakeholders). Additionally, for some categories, stakeholder perspectives differ on the magnitude of costs and benefits (e.g., electric system losses), or whether categories have both costs and benefits (e.g., integration costs).

Stakeholders have different perspectives on the computation of costs and benefits for all of the categories where limited agreement was achieved (above), and additionally for the following categories.

- Water consumption
- RES avoided costs
- PV system orientation

Categories with Significant Disagreement

Significant differences of opinion exist between stakeholders on whether the following costs and benefits should be included in an evaluation of DE or net metering. Differences are largely driven by whether the costs and benefits are incurred by the utility (e.g., societal benefits) or whether the costs and benefits can be reasonably measured or estimated.

- Fuel hedging
- Cost of ancillary services / value of services provided
- Market price mitigation
- Grid security
- Health effects
- Non-compliance-related environmental effects
- Economic development and jobs
- Civic engagement / conservation awareness
- Energy subsidies
- Technology synergies
- Decommissioning costs
- Ratepayer / consumer interest
- Ratepayer cross-subsidization
- Utility systems costs

In conclusion, it is important to note that given different stakeholder opinions on the costs and benefits to include in DE and net metering evaluations, agreement on a common evaluation approach by the Technical Conference stakeholders is unlikely.

KEY OBSERVATIONS OF THE TECHNICAL CONFERENCE

Noteworthy issues identified during the Technical Conference are summarized individually for each workshop and for the closing and opening forums in the following sections of the report. These issues represent the most important concepts distilled from workshop presentations and issues discussed by the stakeholders during the Technical Conference. The following list represents a further distillation of these issues that, in the opinion of the Facilitator, are the most significant observations made during the Technical Conference.

- Some APS rates presently do not reflect net metering offsets that match the value of DE to APS. Solutions should provide for retail rate fairness and equity between DE participants and non-participants.
- Because most APS residential and small commercial rates do not have explicit demand components, these rates are misaligned with actual utility fixed and variable costs. For these rates, DE with net metering produces an under-recovery of fixed costs, further worsening this misalignment.
- The total dollar amount of current subsides caused by DE is relatively low, but are expected to increase significantly with current forecasts of DE. Known rate subsidies caused by other

issues have previously been vetted before the ACC; subsidies caused by DE have not yet been vetted.

- APS rates are set based on embedded costs, not marginal costs, and Arizona regulations do not allow use of a forward-looking, levelized, or forecast test year when computing rates.
- Under PURPA, customers have certain rights to interconnect and receive avoided cost payments for energy exported to the grid.
- Solar DE provides long-term benefits (and costs) to the utility.
- APS uses the Effective Load Carrying Capability (ELCC) computation to determine dependable capacity of solar DE, which is an industry accepted best practice.
- Dependable capacity of solar DE decreases with increasing solar DE implementation; future solar DE installations will provide significantly less capacity value than installations made today.
- Generation simulation modeling suggests that higher penetration of solar DE can cause inefficient generation dispatch.
- Significant differences of opinion exist between stakeholders with respect to which costs and benefits should be considered and what evaluation methodologies and models should be used when evaluating DE and net metering.
- Fuel and energy subsidies are important issues for some stakeholders, but stakeholders are uncertain how to reflect subsidies in cost-benefit studies. Some stakeholders have suggested that energy subsidies are a regulatory policy issue, not a cost-benefit issue.
- If different models are used to evaluate DE and net metering, results may vary significantly because of differences in methodology and assumptions; it will be important for decision-makers to understand these differences.
- Changes in several modeling assumptions and inputs have occurred since the 2009 R.W.Beck Study, including lower natural gas prices, lower CO_2 prices, lower APS load forecast, lower system losses, and higher DE implementation levels, causing lower projections of avoided costs for solar DE resources in the updated SAIC study. The updated 2013 study projects that average avoided costs will be in the range of 6.5 to 10.0 ¢/kWh in 2025, which is approximately 20 to 30 percent lower than the range of results depict for the same year in the 2009 study.
- The solar industry stakeholders prepared a study of avoided costs for solar DE in the APS market area using a methodology and approach that is different from that used in the SAIC study. The study used a Rate Impact Measure (RIM) approach traditionally used when evaluating utility demand-side measures, and included benefits for avoided ancillary service costs, avoided RPS costs, and avoided non-compliance environmental costs. The stakeholder study projects that levelized benefits over 20 years will exceed levelized costs by a ratio of 1.54.
- APS has noted several issues with the stakeholder's study, including lack of an hourly energy cost simulation, energy prices set at levels higher than APS costs, avoided capacity costs beginning in 2013 (instead of 2017 as APS' IRP indicates), not including capacity value degradation of solar DE, double counting of capacity reserves, use of outdated assumptions

for avoided T&D costs, modeling of avoided RPS, and use of non-compliance environmental costs.

- Stakeholders have provided APS with several topics for consideration when developing a proposed solution, including:
  - How will grandfathered rate/incentives be transferred to a new homeowner?
  - Buy-all and sell-all rates may need to be administered as separate tariffs.
  - Rate stability may be critical to customer financing of DE projects.
  - Net metering and DE must be vetted through the ACC for consideration of potential subsidies.
  - Solar DE avoids marginal costs that are higher than embedded cost rates.
  - In a buy-all/sell-all model, how will diversion of DE production be policed?
  - Need to consider whether a buy-all/sell-all model results in tax consequences for customers.

REPORT ORGANIZATION

This report, providing a summary of the Technical Conference, is organized into the following sections.

- Executive Summary
- Opening Forum
- Workshop I: Understanding Rates and Distributed Energy Benefits
- March 14th Stakeholder Call
- Workshop II: Resource Planning and Distributed Energy Costs
- Workshop III: SAIC Model and Other Models
- Workshop IV: Other Policy and Valuation Perspectives
- Closing Forum

The Appendix contains the following Items.

- List of Abbreviations and Acronyms
- Copy of Workshop Presentations and Meetings Notes
- Stakeholder Alignments and Cost-Benefit Matrix
- Catalog of Website Documents
- List of Registered Participants for the Technical Conference

OPENING FORUM

OVERVIEW

The first workshop, the Opening Forum, identified the purpose, subject matter, and framework for the Technical Conference. The Opening Forum provided a high-level exchange of ideas and issues among workshop participants and laid the groundwork for the remainder of the Technical Conference.

The following key issues were raised during the Opening Forum.

- Purpose of the Technical Conference is engagement, education, and collaboration to create a common understanding of issues, challenges, and options.
- Stakeholders desire an open process and a comprehensive cost-benefit study of DE.
- Solutions should provide retail rate fairness and equity.
- The APS net metering program is not broken and does not need to be changed.
- APS rates must recover investment and operating costs.
- APS rates need updating to assure that net metering offsets match the value of DE to APS.
- Concerns were raised that the SAIC study will not address all solar technologies.

WORKSHOP SUMMARY

Purpose and Goals

The Opening Forum was held February 21, 2013, and provided stakeholders an introduction to purpose of the Technical Conference and subject matter to be covered during the remaining workshops. Following an initial welcome by Jeff Guldner, APS Senior Vice President, the workshop Facilitator, Mark Gabriel, reviewed the goals of the Technical Conference and the process that would be used to achieve the goals.

The stated purpose of the workshops was as follows:

As part of the Arizona Public Service Company Renewable Energy Standard (RES) 2013 Implementation Plan deliberations on January 23, 2013, the Arizona Corporation Commission ordered APS to conduct a multi-session technical conference to evaluate the costs and benefits of Distributed Renewable Energy and Net Metering

This conference will evaluate costs and benefits of distributed energy to both renewable and non-renewable customers, and will consider such issues as environmental mandates, changes in generation requirements from distributed energy, localized grid impacts, system losses, and other relevant topics.

In addition to increasing the general knowledge of workshop participants and reviewing stakeholder concerns, the Facilitator identified the following goals for the Technical Conference:

- Create stakeholder collaboration
- Education and engagement
- Meet ACC expectations
- Develop common understanding of issues and options
- Create an understanding of critical challenges
- Alignment on key issues, options and challenges

Stakeholders provided comments on specific goals and topics that they wanted to be addressed through the Technical Conference. These were further refined by the Facilitator for topics that could be addressed through the workshops, and those that were outside the scope of the workshops.

Possible stakeholder topics and goals to be discussed during the workshops:

- Identify costs and benefits of DE (comprehensive)
- Best practices for cost-benefit studies
- Need transparent, data-driven process
- Use industry studies
- Consideration of energy storage
- Fossil and nuclear subsidies
- Stakeholder involvement in studies
- Stakeholder access to data sources used in cost-benefit studies
- Retail rate fairness and equity, rate stability, long-term rate impacts, ratepayer value
- Inadequacy of current rate design
- Cost-effectiveness perspectives (RIM)
- Technology innovation and new business models

Stakeholder topics and goals that may not be addressed by the Technical Conference:

- Need for R&D, pilot studies, new approaches
- Create a sustainable future for DE in AZ
- Qualified solar installer program
- Consumer education when purchasing DE
- Retail rate transparency
- Commission involvement in the process
- Value of storage in the cost-benefit study

Presentation Summaries

Three presentations were provided during the Opening Forum:

- Net Metering Overview, Eran Mahrer, of Solar Electric Power Association
- APS Perspective, Greg Bernosky, Manager, Renewable Energy Program
- Preview of Upcoming Technical Conference (several presenters)

Brief summaries of each presentation are provided below. Workshop meeting notes and copies of full presentations can be found in the Appendix of this report. Audio transcripts of the workshops are available on the www.solarfuturearizona.com website.

Net Metering Overview, Eran Mahrer, SEPA

Eran Mahrer reviewed the status of net metering throughout the United States and discussed some of the opportunities and challenges for utilities and customers, specifically with regard to distributed energy. The following topics were discussed.

- Dramatic issues and unprecedented opportunities
- Changing customer demands - regulatory models require adaptation
- Net-metering is widely available
- Rate impact may not match utility costs and benefits
- Net-metering design, two camps:
  - Net-metering works, don't change it
  - Reevaluate to provide equitable cost distribution and full cost recovery
- Possible net-metering redesigns:
  - Demand-based rates
  - Net cost of service to serve DE customer
  - Value of solar (consumption and production are separate)
- Value attributes of DE are long term
- Long-term and near-term value are not equal
- Recommendations:
  - Quantify value of DE
  - Establish transaction model that supports DE and customers
  - Maintain simplicity
  - Minimize the need for subsidies
  - Maintain recovery of utility costs

APS Perspective, Greg Bernosky, Manager, Renewable Energy Programs

Greg Bernosky reviewed the challenges and objectives of APS concerning net metering and the impact of distributed energy. The following topics were discussed.

- Customers changing how they consume (and produce) energy
- Solar DE is available to a greater number of customers
- Maintain safe and reliable power supply
- Recover infrastructure invest and operating costs
- Modernize rate design to manage cost impacts for both participants and non-participants
- Billing offsets should match utility net avoided costs of DE
  - Identify unbundled costs of service
  - Identify role of incentives or subsidies, if any
  - Make solar DE sustainable through new rate design

Preview of Upcoming Technical Conferences

Several individuals provided a preview of upcoming technical workshops and the subjects scheduled for review.

- Retail rate making
  - Revenue requirements determination
  - Unbundled cost of service determination
  - Rate design development
- Integrated resource planning
  - Avoided operating costs
  - Delayed or avoided facility investments
  - Possible cost increases
  - Utility load shape impacts
- SAIC refresh of R.W.Beck 2009 DE Study
  - Discussion of major changes to key assumptions
  - Review of data sources

Stakeholder Comments and Q&A

During the course of the presentations and at the conclusion of the workshop, stakeholders were invited to ask questions and provide comment. Major topics discussed by stakeholders are provided below.

- Net metering is not broken and does not need to be fixed
- Output of the process should be a comprehensive cost-benefit study
- Various natural gas price and environmental scenarios should be considered as part of the SAIC study
- Concern that single-axis tracking PV, various PV orientations, and solar water heating will not be part of the SAIC study
- Interest in expanding the schedule for the Technical Conference to permit stakeholders the chance to direct the study approach and to participate in SAIC analysis and modeling
- Stakeholders were asked to develop a list of costs and benefits categories for inclusion in the SAIC study

WORKSHOP I

OVERVIEW

Workshop I was held March 7, 2013 and was focused primarily on technical topics of: (i) SAIC study approach and data needs for cost-benefit modeling; (ii) retail rate design; and (iii) impact of solar DE on APS retail rates. Presentations were made by SAIC consultants, a technical expert identified by the Facilitator, and APS staff. The following key issues were raised during Workshop I.

SAIC Study:

- SAIC study will use monitored APS solar PV data, stakeholders will have access to the data.
- SAIC will validate assumptions and results of PROMOD simulations prepared by APS.
- Stakeholders will be provided the data being provided to SAIC.
- SAIC results will be reviewed in a manner that provides transparency.
- SAIC will perform sensitivity analyses.
- Solar water heating is not included in the SAIC study.

Rate Design:

- Existing misalignment of fixed and variable costs and rates for residential and small commercial customers was not caused by DE, but DE makes the problem worse.
- Misalignment of fixed and variable costs and rates is not significant for large commercial customers.
- Arizona regulations do not allow use of a forward-looking, or forecast, test year.
- APS rates are set based on embedded costs, not marginal costs.

DE Impacts on APS Rates:

- The Navigant study investigated the potential for cost shifting and rate impacts caused by solar DE; APS system costs and benefits of solar DE will be addressed by the SAIC study.
- Known rate subsidies have previously been vetted in rate cases before the ACC; subsidies caused by DE have not yet been vetted.
- Subsides caused by DE are currently low, but are expected to increase significantly with current forecasts of DE.
- If benefits exceed costs, then subsidization is reversed (DE participants subsidize non-participants).

WORKSHOP SUMMARY

Workshop I began with a discussion of the purpose and goals of the Technical Conference, consistent with the purpose and goals identified during the Opening Forum. The concept of alignment, which was introduced in the Opening Forum, was further explained and a preliminary list of stakeholder alignments was discussed. (See the summary for Workshop III, below, for the final list of stakeholder alignments developed through the Technical Conference.)

Three presentations were provided during Workshop I:

- Review of Data Sources for the SAIC Study, Joni Batson, SAIC
- Utility Rate Making, Tony Georgis, NewGen Strategies and Solutions
- APS Rates Overview and Impact of Solar DE, Charles Miessner, APS

Brief summaries of each presentation, followed by stakeholder comments and Q&A specific to each presentation are provided below. Workshop meeting notes and copies of full presentations can be found in the Appendix of this report. Audio transcripts of the workshops are available on the www.solarfuturearizona.com website.

Review of Data Sources for the SAIC Study, Joni Batson, SAIC

Presentation Summary

SAIC is updating the 2009 R.W.Beck Study to reflect new assumptions and changes to methodology, including the following.

Key economic and DE drivers that have changes since the 2009 R.W.Beck Study:

- Lower existing and forecast APS loads
- Lower natural gas and CO_2 emission price forecast
- Higher solar DE adoption rates
- Predominantly fixed-plate PV resources

Key modeling assumptions:

- Existing solar DE counts and actual operating performance
- Revised higher forecasts for solar DE for 2015 and 2025
- APS 2012 IRP
- Current APS T&D plans
- Current APS load forecasts, fuel price forecasts, and financial data

SEIA Recommendations for Evaluation of Additional Costs and Benefits

In response to discussions and a request made during the Opening Forum, the Solar Energy Industries Association (SEIA) recommended that the following costs and benefits be given consideration by APS and/or SAIC when performing the cost-benefit evaluation of solar DE.

- Market price mitigation
- Benefits from southwest or west facing orientations of fixed arrays
- Grid security benefits
- Fuel hedge value
- Environmental compliance savings
- Reliability benefits
- Environmental savings (like water)
- Avoided RPS wholesale purchases

APS took under advisement the SEIA recommendations and agreed to respond at a future workshop.

Stakeholder Comments and Q&A

During the course of the presentation, stakeholders asked questions and provided comments. Stakeholder comments and resolutions of stakeholder questions are provided below.

- APS historical monitored solar PV data is being used in the study
- Stakeholders will have access the APS solar data
- Stakeholders will be provided the data being provided to SAIC
- The SAIC results will be reviewed in a manner to provide transparency
- SAIC will use PROMOD simulations of the APS system being prepared by APS
- SAIC will validate PROMOD input assumptions
- SAIC will validate that PROMOD results are consistent with expectations and experience
- The PROMOD model will not be benchmarked to market price data
- SAIC will modify model inputs to perform sensitivity analyses
- The PROMOD modeling will use hourly solar load shapes
- The value of DE from avoided utility capacity is included in the study
- The study needs to consider technology and fuel market scenarios
- Solar water heating should be included in the study

During workshop discussions on the SAIC study and data sources, two comments were raised by stakeholders that were ultimately adopted into the SAIC study: (i) modeled solar implementation should include scenarios of two- and four-times current implementation levels, and (ii) the SAIC study should include results for 2020 (in addition to 2015 and 2025). Additionally, during stakeholder questions and comments, stakeholders voiced their concern that they did not have the same timely access to data assumptions and inputs as SAIC. APS noted that no one, including SAIC, had yet received the full data set (at the time of the workshop). After further discussion, it was decided to extend the workshop schedule to provide the stakeholders additional time to review data and assumptions being provided by APS.

Utility Rate Making, Tony Georgis, NewGen Strategies and Solutions

Presentation Summary

Tony Georgis provided an overview of tasks typically undertaken by electric utilities when designing retail rates and establishing rate levels. Mr. Georgis also discussed issues of subsidization and current APS costs and rate structures. Specific topics covered by Mr. Georgis included the following.

Primary steps in ratemaking:

- Determine revenue requirements
  - All reasonable expenses, cost of capital, taxes, and fair rate of return
  - Test year analysis, known and measurable adjustments

- Allocate costs
  - Functionalize costs (production, transmission, distribution, etc.)
  - Classify costs (demand, energy, customer costs, etc.)
  - Allocate costs among rate classes (load shapes, coincident/non-coincident demand, etc.)
- Design rates

Other topics:

- Subsidization
  - Intra-class subsidization
  - Inter-class subsidization
- APS current costs and rate structures
  - Alignment of variable and fixed costs and revenue
  - Unbundled rate components

Stakeholder Comments and Q&A

Stakeholders received the following resolution to questions relating to retail rate design.

- Lack of alignment of fixed and variable costs and revenue is not caused by solar DE, but solar DE makes the problem worse
- For commercial customers, fixed and variable cost and rate alignment is not as big a problem as it is with residential customers, but variations in load factor can cause subsidization
- When using a historical test year, rates are designed to cover historical, not forecast, costs (Arizona regulations do not allow use of a forward-looking, or forecast, test year)
- Rates are set based on embedded costs, not marginal costs
- When computing rates, non-coincident customer demand is used to measure the cost of facilities required to meet the demand of the customer when DE is not operating

APS Rates Overview and Impact of Solar DE, Charles Miessner, APS

Presentation Summary

Charles Miessner of APS provided an overview of APS rates and specific issues that APS if facing with regard to net metering for solar DE. Mr. Miessner also provided an overview of the study *Net Metering Bill Impacts and Distributed Energy Subsidies* recently performed by Navigant Consulting for APS to review the potential for cost shifting and rate impacts caused by solar DE. Specific topics covered by Mr. Miessner included the following.

- APS major rate classes (types, customer, energy and revenue allocations by class)
- Billing elements and charge types
  - Fixed charges, variable charges, and mixed (tiered rates)
  - Bundled and unbundled components, adjustments
- APS specific rate designs and DE bill savings
  - Example DE billing component savings

  - Example utility cost savings
- Conceptual discussion of cost-shifting *billing gap* issue
  - Cost equity test (utility cost savings = bill reductions, then no adverse impacts)
  - Billing gap (utility cost savings < bill reductions, then costs shifted to non-participants)
  - The lost fixed cost recovery mechanism (LFCR) used to collect fixed costs from all customers, does not correct cross-subsidization
- Review of Navigant Study
  - Characterize cost shifting and rate impacts of DE
  - Evaluate potential cost equity issues
  - Assess compatibility of APS rates for rapidly growing DE
  - Study was not a cost-benefit analysis, evaluation of utility financing/earnings, or quantification of impacts across all customers
- Major Findings of the Navigant Study
  - Under current rate designs, DE shifts costs to nonparticipating customers
  - Current APS rate designs are not sustainable with a growing level of DE
  - Net-metering exacerbates cost shifting
  - Cost shifting is highest for residential and small business customers because the rates rely on kWh charges for fixed cost recovery

Stakeholder Comments and Q&A

Stakeholders made the following comments or received the following resolution to questions relating to APS rates and rate impacts of solar DE.

- The Navigant study used actual metered solar DE, applied to representative customers, to investigate the potential for cost shifting and rate impacts caused by solar DE.
- The Navigant study focused on rates classes with the greatest potential for cost shifting; other rate classes were not studied.
- The Navigant study focused on current impacts, not long-term benefits. However, both costs and rates grow over time, so problem will persist.
- Other known types of rate subsidies have already been vetted in rate cases; subsidies caused by DE have not yet been vetted.
- Subsides caused by DE are small today but are expected to grow significantly over time.
- Similar cost shifting issues exist for energy efficiency and conservation, but the level of cost shifting per participant is lower.
- Cost savings are based on installed assets, not future avoided costs.
- APS may receive RES credit for DE, which provides a benefit to APS.
- If benefits exceed costs, then subsidization is reversed.
- The billing gap for APS is approximately 15 cents, higher than referenced in the 2009 R.W.Beck Study, largely due to falling natural gas costs.
- The Navigant study did not consider costs for DE integration.

- Solar DE acts as a hedge against future natural gas prices. However, DE does not eliminate all risks and may shift risk exposure from market volatility to fixed obligation.
- Large numbers of DE installations improve diversity and reliability.

MARCH 14TH STAKEHOLDER CALL

A conference call, facilitated by Mark Gabriel, was held among interested stakeholders, including APS, to report on the status of APS' response to stakeholder data requests, to review a list of additional costs and benefits data considerations that was initially presented by SEIA during Workshop I, and to discuss the schedule of future workshops. The majority of the call entailed a question and answer review of the additional data considerations begin proposed by SEIA. Meeting notes from the call are included in the Appendix to this report.

The proposed data items and associated stakeholder perspectives discussed during the call were ultimately incorporated into the Cost-Benefit Matrix, originally introduced during Workshop II and more fully developed through the remainder of the Technical Conference. The final version of the Cost-Benefit Matrix is included in the Appendix to this report, and a summary of the matrix was discussed in the Executive Summary.

WORKSHOP II

OVERVIEW

Workshop II was held March 20, 2013 and was focused primarily on the technical topic of computing avoided utility costs of Net Energy Metering (NEM) and DE. Presentations were made by a stakeholder technical expert, a technical expert identified by the Facilitator, and APS staff. The following key issues were raised during Workshop II.

Evaluation of NEM in California:

- Under PURPA, customers have rights to interconnect, offset their own load, and receive avoided cost payments for energy exported to the grid.
- NEM from solar DE provides long-term benefits (and costs).
- Evaluation of NEM in California indicates little to no cross subsidization, on average, under current market conditions, using the analytic approach traditionally used for such evaluations in California.

Utility Modeling of Avoided Costs of DE:

- Use of an Effective Load Carrying Capability (ELCC) computation to determine the dependable capacity of solar DE is an industry accepted best practice (ELCC computes the probabilistic impact of DE on system reliability across all hours, not just the peak hour).
- Dependable capacity decreases with increasing solar DE implementation; the incremental capacity value of future solar DE installations will be significantly less than the value today.
- Generation simulation modeling suggests that significant quantities of solar DE can cause less efficient generation dispatch (i.e., increased unit starts and ramping, scheduling for dual peaks, increased requirements for regulation, reserves, and dump energy).
- Installing solar DE capacity prior to utility need for capacity can diminish the value of DE if the utility does not have a market to sell surplus capacity.

Different Opinions on how to Model Avoided Costs of NEM and DE:

- There are significant differences of opinion on evaluation methodologies and models that should be used when evaluating DE and NEM resources. Significant areas of disagreement include:
  - Simulation of dependable capacity and diminishing value of DE/NEM
  - Detailed generation simulation or market price valuation
  - Simulation of DE/NEM impact on ancillary services or avoided cost tariff rates
  - Modeling of discrete avoided/deferred generation and T&D facilities or avoided marginal costs of capacity
  - Period over which costs and benefits are computed and summed

- There are significant differences of opinion on which avoided utility costs should be included (and how the avoided costs should be computed) when evaluating DE and NEM resources. Significant areas of disagreement include:
  - Cost of CO_2/GHG allowances
  - Avoided T&D capacity and O&M costs
  - Avoided RPS costs
  - Value of fuel and power market price hedging/mitigation

WORKSHOP SUMMARY

Workshop II began with a discussion of the purpose and goals of the Technical Conferences, consistent with the discussion in prior workshops. Existing and potential topics for alignment were reviewed and discussed. (See the summary for Workshop III, below, for the final list of stakeholder alignments developed through the Technical Conferences.)

Three presentations were provided during Workshop II:

- Evaluating the Benefits and Costs of Net Energy Metering in California, Tom Beach, Crossborder Energy
- Resource Planning & Distributed Energy, Bob Davis, nFront Consulting
- APS Resource Planning, Paul Smith, APS

Brief summaries of each presentation, followed by stakeholder comments and Q&A specific to each presentation are provided below. Workshop meeting notes and copies of full presentations can be found in the Appendix of this report. Audio transcripts of the workshops are available on the www.solarfuturearizona.com website.

Evaluating the Benefits and Costs of Net Energy Metering in California, Tom Beach, Crossborder Energy

Presentation Summary

Tom Beach presented a review of the assumptions, methodology, and results of a study he prepared that examined the value of NEM in California. The study used a model developed by E3 that is commonly used in California to compute marginal costs and benefits when evaluating demand-side resources. Mr. Beach updated major assumptions used in a 2009 E3 study of NEM, and computed net present value costs and benefits for net energy exports of NEM customers in each of the three IOU service areas in California.

Mr. Beach concluded that in California, crediting exported energy through NEM, on average, will not result in an adverse cross-subsidization of participants by non-participants. Instead, in many cases the opposite occurs – avoided cost benefits provided by solar NEM customers will exceed the credit received through net-metered exports over the life of the solar resource.

A summary of Mr. Beach's presentation follows.

- NEM is simple for participating customers to understand, but impact on non-participating customers is complex
- Under PURPA, customers have rights to interconnect, offset their own load, and receive avoided cost payments for energy exported to the grid
- Do NEM credits accurately capture the value of exported power?
  - NEM evaluations use the same approach as demand-side resource evaluations
  - Cost-effectiveness of NEM (net export) is different than DE (all DE production)
  - NEM cost-effectiveness should be measured using the RIM test
  - NEM from DE is a long-term resource (long-term costs and benefits)
  - Costs are lost utility revenue, integration costs, incremental administration
  - Benefits are avoided generation investment and operating costs, avoided environmental costs, RPS value, avoided T&D investment, avoided losses
- Major assumptions, updated from 2009 CPUC-E3 study
  - Updated utility rates and fuel price forecasts
  - Avoided energy costs equals all-in CCGT cost less CT capacity cost
  - Avoided capacity costs equals CT fixed cost spread to top 250 hours
  - Avoided T&D losses
  - Avoided GHG allowances
  - Reduced ancillary services costs
  - Avoided T&D marginal capacity costs
  - Avoided RPS costs
- Methodology
  - Evaluate bill credits and avoided utility costs for NEM exports
  - 20-year levelized costs and benefits
  - Compute for multiple bins of different customer size and PV system size
- Conclusions:
  - Solar NEM has a positive net benefit (utility costs are reduced more than are paid through NEM rates credits)
  - Two of three California IOUs show no adverse cross-subsidization between residential participating and non-participating customers
  - All three IOUs show no cross-subsidization for C&I customers
  - Greater adoption of TOU rates reduces cross-subsidization

Stakeholder Comments and Q&A

Stakeholders made the following comments or received the following resolution to questions asked relating to Mr. Beach's presentation.

- Utility integration costs were not modeled (assumptions for integration costs have not yet been adopted by California)
- CO_2 allowance costs are assumed to be $10-13 for 2013

- Avoided T&D costs are based on regression methodology
- Once RPS is met, DE has incremental RPS value through exports and increasing RPS standards
- Intermittency of DE is mitigated by aggregated installations; benefits may be lower on individual circuits
- In the E3 model, solar DE capacity does not diminish with increasing installations
- Some studies indicate a correlation between cloud cover and decreased demand; effect could take hours to occur in AZ
- The E3 model captures hedge cost value by using forward market prices

Resource Planning & Distributed Energy, Bob Davis, nFront Consulting

Presentation Summary

Mr. Davis presented an overview of the methodologies that electric utilities use to compute avoided power supply costs. Mr. Davis provided example calculations to demonstrate how avoided costs and benefits are prepared and provided an example computation that closely mirrors the avoided costs that were being prepared for the SAIC study.

Highlights from Mr. Davis' presentation follow.

General Utility Planning:

- Electric utilities are responsible for providing reliable power at low cost
- Utilities may consider demand-side resources if they pass specific benefit/cost tests (utility cost test, RIM test, TRC test)
- Solar DE impacts utility operations and planning
  - Changes in generation dispatch (generally reduces operating costs, but can also increase operating costs)
  - Reduces need for future generation capacity additions
  - Costs to integrate solar DE

Evaluation process:

- Develop solar DE load shapes and forecast implementations
- Adjust DE load shapes for energy and demand losses
- Dependable capacity of solar DE
  - Effective load carrying capability (ELCC)
  - Coincident with electric system peak
  - Diminishing capacity value with increasing penetration
- Avoided capacity costs
  - Assess utility capacity additions with/without solar DE
  - Identify avoided or deferred generating units or capacity purchases
  - Capital costs of avoided or deferred generating unit and related facilities
  - Other fixed O&M costs of avoided or deferred unit
- Compute avoided marginal energy costs

- Generation dispatch simulation
- Costs for fuel, variable O&M, emission allowances, start-up
- Simulation with and without solar DE
- Compute avoided marginal costs

- As larger quantities of solar DE are installed
  - More difficult to accommodate DE resources in the generation dispatch
  - Inefficient dispatch operations can result
  - Reduced value of solar DE that precedes planned utility capacity additions

Conclusions:

- Solar DE can avoid both energy and capacity related utility costs
- Dependable capacity of solar DE is important
- Solar DE benefits may be less than anticipated as a result of dispatch inefficiencies and timing of solar DE installations

Stakeholder Comments and Q&A

Stakeholders made the following comments or received the following resolution to questions asked relating to Mr. Davis' presentation.

- Solar DE is not modeled to avoid large lumpy generating capacity additions; APS is planning small 100 MW increments of generation additions when evaluating avoided capacity costs.
- There is no industry-preferred model for analyzing capacity expansion.
- APS is using PROMOD to model energy costs, not market price modeling; DE may cause dispatch inefficiencies for APS that would not be reflected by a market price forecast.
- Comments on whether DE production can be sold to a neighboring subdivision, thus eliminating the need for the LFCR rate mechanism; but APS would still need to provide full T&D facilities and customer services to serve 100 percent of the load sometimes.
- Large lumpy capacity additions eliminate capacity additions for a period of time following the addition; APS models both generating unit additions and purchased capacity to mitigate this effect.
- Discussion on timing of avoided costs is compelling; APS can only include actual incurred costs in ratemaking; for example, future costs escalators in contracts cannot be monetized in rates today.
- ELCC is a rigorous way of looking at resource need.
- Economic benefits of solar orientation and single axis tracking is minimal.
- Surplus DE can help improve system reliability and mitigate loss of generating assets (example: offline nuclear unit in California).
- Stakeholders and APS disagree on whether to model "lumpy" capacity additions.

APS Resource Planning, Paul Smith, APS

Presentation Summary

Paul Smith summarized APS' capacity expansion plans and discussed how solar DE is simulated in the APS planning process. He discussed how APS simulates dependable capacity for solar DE and described how solar DE can affect generation dispatch. Mr. Smith reviewed significant economic and market changes that have occurred since the 2009 R.W.Beck Study was performed, and discussed how those changes would affect modeling of APS avoided costs.

Highlights from Mr. Smith's presentation are summarized below.

- Review of APS future load growth and generating capacity need (first year 2017)
- Solar DE energy value simulated using PROMOD
  - Detailed simulation of APS costs of generation dispatch
  - Total APS energy costs with and without solar DE
  - Operational challenges can occur during low load periods (ramp up, ramp down, scheduling for dual peaks, increased unit starts, intermittency, dump energy)
  - Integration costs
  - Predominant avoided energy is CC energy
- Key changes from 2009 R.W.Beck Study
  - APS load forecast (lower)
  - Solar DE implementation (higher)
  - Fuel prices, especially natural gas (lower)
  - CO_2 prices (lower)
  - Capacity cost of new CT (higher)
  - Fixed O&M of new CT (higher)
  - NG reservation fee (higher)
- Dependable solar DE capacity based on ELCC analysis
  - Industry best practice methodology
  - Probabilistic – solar DE capacity established over many hours not just single peak hour
  - Dependable capacity decreases with increasing solar DE implementation
  - Incremental capacity value of future solar DE installations will be less than value today

Mr. Smith also reviewed the list of additional cost and benefit data considerations that were proposed by the stakeholders during Workshop I, and more fully developed during a conference call held March 14, 2013. Mr. Smith presented APS' position regarding each of the proposed data cost-benefit data considerations.

- APS general considerations
  - Must accrue real, measurable benefits to our customers
  - Impacts must be recognized in cost of service ratemaking
  - Test year versus future looking
  - Does not include societal benefits/externalities

- Market price mitigation
  - Direct cost savings included in PROMOD modeling
  - NG market influence unclear
  - APS not in an LMP market
  - APS is both buyer and seller, uncertain net effect
  - Price elasticity uncertain
- Grid security – Already addressed by ELCC analysis
- Fuel hedge value
  - APS models forward price for NG (captures market view)
  - APS has a 3-year hedge program (volatility diminishes beyond 3 years)
- Environmental compliance savings – Already included in PROMOD simulation
- Reliability benefits
  - Spinning and operating reserves already modeled in PROMOD
  - Solar DE can increase requirements for ancillary services (ignored in APS analysis)
- Avoided RPS purchases
  - No value above compliance (APS is forecasting RPS to exceed regulatory targets)
  - Value only for the net cost of RPS above conventional resources

Stakeholder Comments and Q&A

Stakeholders made the following comments or received the following answers to questions pertaining to Mr. Smith's presentation.

- Diminishing value of solar DE capacity is caused when the utility peak hour is pushed later in the day (possibly to nighttime hours).
- Solar DE currently represents a small portion of the APS peak.
- New technologies (e.g., storage) may address some of the issues with diminishing capacity value; APS should consider only short-term forecasts, with regular updates to reflect changing in technologies.
- Market price mitigation, even if small, should not be zero.
- APS is a net buyer of market energy.
- Emission savings are modeled as sensitivity cases in the IRP.
- Southwest/west orientation provides increased capacity value; energy impacts are uncertain.

Cost-Benefit Matrix

Following the presentation by Paul Smith, the workshop participants discussed the possibility of developing a comprehensive list of all cost and benefit categories that had previously been discussed or otherwise identified during the prior workshops and the March 14th Conference Call. It was believed that a comprehensive list would aid in a more systematic review and discussion of these items. The workshop participants suggested that the list could be developed into a matrix that would allow different stakeholder groups to document their views and opinions on whether each specific cost-benefit category should be included when evaluating utility costs and benefits of DE resources. As part of the discussion, stakeholders identified three additional subjects to add to the list: civic awareness, grid security, and impact of future new technologies.

The Facilitator was tasked with developing an initial *cost-benefit matrix* that itemized each previously identified cost-benefit data item, or category, and included generic definitions for each category that the stakeholders could review and approve at the next workshop. (The final Cost-Benefit Matrix developed over the course of the Technical Conference is provided in the Appendix.)

WORKSHOP III

OVERVIEW

Workshop III, held April 11, 2013, covered a number of topics, including reviews of: (i) prior alignments and transition to the cost-benefit matrix; (ii) subsidies in electricity industry; (iii) a DE evaluation model being contemplated by certain stakeholders; and (iv) draft SAIC Study results. Presentations were made by the Facilitator, a stakeholder technical expert, and SAIC consultants. The following key issues were raised during Workshop III.

- Fuel and energy subsidies are important issues from some stakeholders, but stakeholders (and APS) are uncertain how to reflect subsidies in the Technical Conference and cost benefit studies. The issue seems to be a policy issue, not a cost-benefit issue.
- If a study is performed using the DGValuator model, it likely could be used to project costs and benefits of solar DE resources in the APS service area over the over the life of the DE resources. Results from the model would be expected to be very different from results produced by SAIC (the SAIC study projects 3 ¢/kWh in 2015, while a recent DGValuator study projects 10 ¢/kWh). It will be important to understand differences in assumptions and methodology used by the two models.
- The DGValuator model has the ability to simulate several avoided cost components that APS does not believe are applicable to its electric system and actual operating costs.
- Changes in several major modeling assumptions since the 2009 R.W.Beck Study, including lower natural gas prices, lower CO_2 prices, lower APS load forecast, lower system losses, and higher DE implementation levels, have caused lower projections of avoided costs for solar DE resources in the updated SAIC study. The updated 2013 study projects average avoided costs to be in the range 6.5 to 10.0 ¢/kWh in 2025, which is approximately 20 to 30 percent lower than the range of results depict for the same year in the 2009 study.

WORKSHOP SUMMARY

Workshop III began with the introduction of a new Lead Facilitator for the Technical Conference, Bob Davis, of nFront Consulting. Mr. Davis replaced Mark Gabriel, who accepted a new position as CEO of the Western Area Power Administration. Mr. Davis was already familiar with the Technical Conference, having presented during the Opening Forum and Workshop II, and having been a member of the original R.W.Beck team that conducted the 2009 Solar DE study.

Following a review of the purpose and goals of the Technical Conference, Mr. Davis identified four major topics to be covered in Workshop III:

- Review of Alignments and the Cost-Benefit Matrix, Bob Davis, Facilitator
- Discussion of Energy Subsidies, Roundtable Discussion Lead by Bob Davis
- Applying DGValuator to Quantify Value of Solar in APS Service Territory, Tom Hoff, Clean Power Research

- SAIC Distributed Energy Model & Analysis, Scott Burnham, SAIC

Brief summaries of each presentation, followed by stakeholder comments and Q&A specific to each presentation are provided below. Workshop meeting notes and copies of full presentations can be found in the Appendix of this report. Audio transcripts of the workshops are available on the www.solarfuturearizona.com website.

Review of Alignments and the Cost-Benefit Matrix, Bob Davis, Facilitator

Discussion

The Alignment process conducted during the first three workshops was discussed. Many workshop participants had previously expressed concerns with the alignment process: what was meant by alignment, how would the alignments be used, and whether the alignment process could effectively deal with the opposing views of different stakeholder groups. Furthermore, it was noted that the many technical issues addressed in Workshops I and II, and continuing with Workshop III, reflected subject matter on which alignment would be difficult to achieve.

Mr. Davis proposed that it might be best in some instances to recognize that different opinions were to be expected. In these instances, a structured discussion and identification of key differences may be more helpful than attempting to find limited areas of alignment. Assuming there were no stakeholder objections, Mr. Davis proposed that the alignments previously established through Workshop II be reviewed one final time and finalized in this workshop, with no plans to add to the list in future workshops.

Final List of Alignments

The following list documents alignments agreed upon by the Technical Conference stakeholders through Workshop II.

1. Transparency is critical.
2. Subsidies for all fuel sources should be considered.
3. Studies in addition to the Beck (SAIC) study should be considered.
4. Consumer education is important.
5. There is a need for continued innovation and new approaches.
6. Definition of net metering: *Net metering is a billing mechanism that credits solar system owners for the electricity exported onto the grid. Under the simplest implementation of net metering, a utility customer's billing meter runs backward as solar energy is generated and exported to the electricity grid and forward as electricity is consumed from the grid.*
7. DE rate impacts can occur through behind-the-meter rate offsets (self-supply) as well as net metering bill credits.
8. APS rates are based on historical test years.
9. DE impacts both costs to serve and revenues collected.
10. DE customers have a unique load profile, benefits and costs.

Cost-Benefit Matrix

Mr. Davis proposed that the stakeholders continue development of the cost-benefit matrix as a convenient template for documenting views of different stakeholder groups. Once complete, the cost-benefit matrix would permit a review of areas of agreement and disagreement for stakeholder groups on key topics affecting the evaluation of solar DE.

A preliminary list of cost-benefit categories and definitions was presented to the stakeholders for comment, and minor edits to the matrix definitions were recommended. Additionally, stakeholders requested that the category Technology Synergies be added to the cost-benefit matrix. A volunteer subgroup of stakeholders was identified to develop the perspectives of the solar stakeholder for each cost-benefit category. APS and the stakeholder group were asked to provide draft perspectives before the next workshop. (The final Cost-Benefit Matrix developed over the course of the Technical Conference is provided in the Appendix.)

Discussion of Energy Subsidies, Roundtable Discussion, Lead by Bob Davis, Facilitator

Presentation Summary

Mr. Davis reminded the workshop participants that the subject of subsidies originated from a discussion of retail rate cross-subsidies between DE program participants and non-participants; federal and state subsidies to industries are a different subject. In effect, all APS customers benefit from any subsidies that APS receives directly or indirectly from other sources. Information on federal subsidies for 2010, published by the Energy Information Administration, was reviewed at the workshop. This is the most recent information on subsidies that was readily available. It was also noted that information on subsidies was difficult to obtain and was often contradictory between different reports. Furthermore, reliable data on state-provided subsidies is difficult to find.

Highlights of the EIA data on federal subsidies to the electricity industry for 2010.

- $11.9B total electricity-related subsidies in 2010
  - 40% direct expenditures
  - 28% tax-related subsidies
  - 22% R&D
  - 5% federal power
  - 5% load guarantees
- Renewables received 55% of subsidies in 2010, but provided 10% of energy
- Coal, natural gas, and oil electricity industries received 16% of subsidies and provided 70% of energy

Stakeholder Comments

Stakeholder comments regarding subsidies are summarized below.

- All fuel sources should be considered

- Workshop participants are uncertain how to reflect subsidies in the technical conferences and cost benefit study
- Subsidies should be added to the Cost Benefit Matrix [completed]
- Total subsides of $11B are approximately 4% of electric industry gross revenue
- What are subsidy levels in current APS rates? [APS provided in response to data request]
- C&I solar DE customers provide a reverse subsidy
- Renewable industries receive large subsidies because they are not yet mature
- Federal subsidies are not relevant to ACC rate policies
- Tax subsidy discussion is important; the sun is not taxed, other fossil fuel and generation receive subsidies
- Renewables and clean technologies would be more competitive if ratepayers paid the true cost of energy from other sources

Applying DGValuator to Quantify Value of Solar in APS Service Territory, Tom Hoff, Clean Power Research

Presentation Summary

Tom Hoff presented the DGValuator model developed by his company and described how it has been used in other jurisdictions to evaluate the value of solar DE. The stakeholder Interstate Renewable Energy Council (IREC) is coordinating with Mr. Hoff to perform a solar DE costs-benefit evaluation specific to the APS system based on the APS data responses provided through the Technical Conference.

Topics covered by Mr. Hoff are summarized below.

- Benchmark DGValuator using SAIC study results
- Produce range of values for various costs and benefits
  - Value of solar to utility
  - Value of solar to ratepayers and taxpayers
- Review of other Clean Power Research studies
  - Austin Energy – Design solar tariff representing utility value of solar
  - PA and NJ MSEIA Study – Full value of solar (utility, ratepayers, taxpayers)

DGValuator Methodology:

- Historical solar irradiation data
- Utility value of solar (costs and benefits)
  - Fuel/energy – marginal cost of CCGT
  - Capacity – capital costs for CCGT
  - T&D capacity – average cost of long-run capacity upgrades
  - Environmental compliance – REC price
  - Fuel price hedge – cost to minimize fuel price uncertainty
  - Marginal losses by benefit category
  - Integration costs

    - Solar DE capacity developed using ELCC
- Ratepayer and taxpayer value of solar (societal benefits)
    - Economic development – net increase in jobs/tax revenues
    - Environmental value – future cost of environmental mitigation
    - Security enhancement – value of avoided outages
    - Market price reduction – price elasticity

Stakeholder Comments and Q&A

Stakeholders made the following comments or received the following answers to questions pertaining to Mr. Hoff's presentation.

- Ratepayers don't pay for all of the modeled costs and benefits.
- Solar DE acts like a 30-year market price hedge, but utilities don't hedge for 30 years (too expensive). It is a policy question on whether to include hedging value.
- Value of solar for Austin (12.5 ¢/kWh) and MSEIA (30 ¢/kWh) are different based on the value categories that were modeled.
- T&D and reliability is examined on a system-wide basis.
- Uncertain how market price reductions apply to AZ; uncertain how to segregate transmission congestion effects from T&D deferrals.
- Market price reductions may affect other off-system sales.
- Funds spent in the local economy may have more economic benefit than funds spent by the utility.

SAIC Distributed Energy Model & Analysis, Scott Burnham, SAIC

Presentation Summary

Scott Burnham, assisted by Joni Batson and Charles Janechek, of SAIC, reviewed the results of the SAIC 2013 Updated Solar PV Value analysis. Mr. Burnham reviewed the primary changes in the analysis that have occurred since the original R.W.Beck Study was performed in 2009 and described the solar DE implementation scenarios that were modeled. The SAIC team discussed the methodology used to compute avoided costs for transmission and distribution facilities, and generation energy and capacity.

The following topics were reviewed by the SAIC team. Complete results for the SAIC study can be found in the Appendix and in the final SAIC Report posted on the www.solarfuturearizona.com website.

- 2013 Refresh Study
    - Leverage 2009 Study methodologies
    - Target years 2015, 2020, 2025 [2020 was added based on stakeholder feedback]
- Changes in key assumptions
    - Depict higher anticipated DE implementation
    - Lower NG prices

  - Lower CO_2 prices
  - Lower load forecast
  - Lower assumed demand and energy losses
- DE Implementation scenarios [consistent with stakeholder feedback]
  - Low – meets compliance
  - Expected – approximately twice compliance
  - High – approximately four-times compliance
- Avoided costs
  - Avoided generation energy (modeled in PROMOD)
  - Avoided generation capacity and associated transmission
  - Deferment of distribution, sub-transmission, and transmission projects

Summary Results:

- No avoided distribution costs. Analysis found that an insignificant number of distribution projects can be deferred (0.6%).
- Four sub-transmission projects were identified as possible deferrals in the target years under the expected and high scenarios.
- No load-related transmission projects were identified for deferral.
- Avoided generation costs (Nominal $)
  - Avoided energy costs (PROMOD) $88M to $290M (Low to High case, 2025)
  - Avoided capacity costs $30M to $45M (Low to High case, 2025)
  - Avoided transmission interconnection $5M to $8M (Low to High case, 2025)
- Total avoided costs (Nominal ¢/kWh):
  - 2015 - 3.0 ¢/kWh (all cases)
  - 2020 - 6.6 to 8.0 ¢/kWh (High to Low case)
  - 2025 - 6.5 to 10.0 ¢/kWh (High to Low case)

Stakeholder Comments and Q&A

Stakeholders made the following comments or received the following answers to questions pertaining to the SAIC presentation.

- Study analyzed the incremental value of new DE installations; existing installations were modeled but value was not computed for existing installations; rate design impacts were not considered in this cost benefit study.
- Natural gas and CO_2 price sensitivities were analyzed. [Presented by SAIC at the conclusion of the workshop.]
- Solar DE is modeled as forecast energy and demand impacts (not number of installations), therefore solar DE technology improvements are captured by the study.
- Actual monitored DE production was used in the study.
- Losses were assumed to be constant and not vary by load or period.
- Reactive power provided by solar DE was not evaluated.

- Solar DE is projected to defer upgrades on five distribution feeders out of 1,351 feeders in the APS system, or approximately one-third of the planned distribution feeder upgrades by 2025.
- The PROMOD simulations were based on the latest APS IRP dataset.
- NG and CO_2 price sensitivities were analyzed (included in final report).
- NG fuel price sensitivity is 30% higher, which captures market price increases since the NG price forecast was developed.
- Study evaluated the value of solar DE; the study did not consider the value of storage.
- Solar water heating was not studied; the most dramatic growth is in solar PV; solar water heating will be considered when APS presents its solution.
- Tom Hoff's presentation shows avoided energy costs of 10 ¢/kWh, while the SAIC study shows a value of 3 ¢/kWh; the 3¢ value is consistent with current NG prices and a CC heat rate; uncertain how Mr. Hoff's value is calculated.
- Should the study consider even lower implementation scenarios?

Following the formal close of the workshop, the SAIC team demonstrated to interested stakeholders aspects of its T&D avoided cost evaluation models and results for higher natural gas and CO_2 price sensitivity cases.

WORKSHOP IV

OVERVIEW

Workshop IV was held May 9, 2013 and covered a number of varied topics, including: (i) review of the cost-benefit matrix; (ii) results of a stakeholder study of solar DE value in the APS region; (iii) presentation on creating sustainable solar markets in California; (iv) discussion of the evolution of net metering markets throughout the U.S.; and (v) discussion of conceptual APS rate and incentive solutions.

The following key issues were raised during Workshop IV.

- Tom Beach prepared a study of avoided costs for solar DE in the APS market area based on assumptions for avoided energy costs that closely matches prices at Palo Verde. The study includes as benefits avoided ancillary service costs, avoided RPS costs, and avoided environmental costs (set at values referenced in APS' IRP sensitivity cases). The analysis includes DE incentive payments paid to participating customers. The study was performed as a 20-year RIM analysis, with a resulting benefit/cost ratio of 1.54.
- APS has noted several issues with Mr. Beach's study, including lack of an hourly energy cost simulation, energy prices set at levels higher than APS costs, avoided capacity costs beginning in 2013, potential double-counting of capacity reserves, modeling of avoided T&D costs that are not believed to exist, modeling of avoided ancillary service costs and RPS, and use of incorrect environmental compliance costs.
- Future APS rate solutions may need to consider an unbundling of costs of services, similar to plans being made by SDG&E. Unbundled costs and rates will more correctly incentivize customer DE production patterns and technology solutions.
- Significant issues that APS may need to consider when developing its proposed solution:
  - How will grandfathered rate/incentives be transferred to a new homeowner?
  - Buy-all/sell-all rates may need to be administered as separate tariffs.
  - Rate stability may be key to customer financing of DE projects.
  - Net metering and solar DE need to be vetted through the ACC for potential subsidies.
  - Solar DE avoids marginal costs that are higher than embedded cost rates.
  - In a buy-all/sell-all model, how will diversion of DE production be policed?
  - Does PURPA supersede enforcement of a buy-all/sell-all model?
  - Need to consider whether a buy-all/sell-all model results in tax consequences for customers.

WORKSHOP SUMMARY

Following a review of the purpose and goals of the Technical Conferences, Mr. Davis identified five major topics to be covered in Workshop IV:

- Review of the Cost-Benefit Matrix, Bob Davis, Facilitator
- Benefits and Costs of Solar Distributed Generation for APS, Tom Beach, Crossborder Energy

- Creating a Sustainable Solar Market, Chris Yunker, SDG&E
- The Evolution of Net Metering, Rate Design, and the Utility Business Model, Ron Binz, Public Policy Consulting
- APS Conceptual Solutions, Chuck Miessner, APS

Brief summaries of each presentation, followed by stakeholder comments and Q&A specific to each presentation are provided below. Workshop meeting notes and copies of full presentations can be found in the Appendix of this report. Audio transcripts of the workshops are available on the www.solarfuturearizona.com website.

Cost-Benefit Matrix, Bob Davis, Facilitator

Discussion

Workshop IV began with a review of the latest version of the Cost-Benefit Matrix. As of Workshop IV, three stakeholder groups had added their perspectives to the matrix, including APS, stakeholders representing large commercial and industrial customers, and environmental stakeholders. A placeholder for the solar stakeholders was also developed and added to the matrix by the Facilitator, and was intended to serve as a strawman for the solar stakeholders to develop their official perspective. New categories and definitions added in response to the last workshop were reviewed. (The final Cost-Benefit Matrix developed over the course of the Technical Conference is provided in the Appendix.)

Stakeholder Comments and Q&A

Stakeholders provided the following comments relating to the Cost-Benefit Matrix.

- Some DE technologies are missing; suggest adding perspectives for other technologies like solar water heating. SWH stakeholders were encouraged to add their own unique perspective to the matrix.
- Ratepayer cross-subsidization category seems one-sided. However, definition reflects that subsidization can flow either way.
- Schools may have a unique load profile and rate impacts of DE. This stakeholder group was encouraged to add their own perspective to the matrix.
- Ratepayer and consumer interests are important, but difficult to enumerate. No specific stakeholder group has been identified during the Technical Conference as representing the residential and small commercial retail classes that could fill this role for the Cost-Benefit Matrix.

Benefits and Costs of Solar Distributed Generation for APS, Tom Beach, Crossborder Energy

Presentation Summary

Tom Beach reviewed the results of a study he conducted to evaluate the value of solar DE output using assumptions for the APS market area. Mr. Beach used assumptions derived from APS' IRP documents, the solar DE update study being performed by SAIC, and the 2009 R.W.Beck Study.

The following topics summarize the presentation provided by Mr. Beach.

- Study overview
  - Evaluate DE not NEM
  - RIM test, 20-yr analysis
- Benefits (avoided costs)
  - Generation energy and capacity
  - Ancillary service & capacity reserves
  - Transmission and distribution
  - Environmental compliance
  - Avoided RPS
- Costs
  - Lost retail revenues
  - DG Incentives
  - Integration costs
- Major assumptions
  - NG price forecast similar to SAIC study
  - Avoided energy costs (Jun-Sep) – CT at 9,400 Btu/kWh
  - Avoided energy costs (other months) – CC at 7,300 Btu/kWh
  - Avoided capacity costs somewhat consistent with SAIC study
  - Ancillary services set to $5/MWh
  - Capacity reserves modeled at 15%
  - Avoided T&D based on assumptions from both SAIC study and 2009 R.W.Beck Study
  - Environmental costs set equal to APS IRP sensitivity cases
  - Value of avoided RPS based on APS IRP enhanced renewable portfolios
  - DE incentives modeled as ~20 ¢/kWh for residential and ~10 ¢/kWh for commercial participants
- Results (20-yr levelized)
  - Benefits 21.5 to 23.7 ¢/kWh
  - Costs 13.9 to 15.5 ¢/kWh
  - Benefit/cost ratio is 1.54
  - Benefits exceed costs for both residential and commercial classes

Stakeholder Comments and Q&A

Stakeholders made the following comments or received the following answers to questions pertaining to Mr. Beach's presentation.

- Hourly dispatch was not modeled
- On the APS system, CTs are run only a few hours per day in the summer, CC energy may be a better estimate of on-peak energy costs for APS. But, the energy prices used for the study are generally consistent with Palo Verde market prices.

- Generating capacity is assumed to be avoided beginning in 2013, but APS does not need to add capacity until 2017.
- The Study is computing the value of a 2013 DE installation and does not consider the diminishing value of DE capacity with increased installations.
- APS costs for ancillary services are about half of the rates that are used in the model.
- ELCC already incorporates the 15% capacity margin.
- When power exported from a DE resource is consumed by a neighbor, the utility does not have to invest in T&D because the power is flowing only a few feet. This is a misconception, DE resources only provide energy and do not provide all of the services provided by the utility; unless the neighbor disconnects from the grid and receives all services from the DE resource, the utility is still providing services. DE is diversified, as utilities become more familiar with DE resources, they will plan for fewer resources.
- The study used the 2009 R.W.Beck Study for assumptions for avoided transmission costs because the SIAC study did not find any load-related avoided transmission costs.
- Because existing installations are included in the study, shouldn't the historical cost of incentives also be included? It is appropriate to include the cost of incentives/rebates since these contribute to the program costs covered by ratepayers.
- Lost retail revenue is modeled at 19.7 cents, instead of current rates at 15.5 cents; the value represents a 20-year levelized value.
- A net positive value in theory means APS could raise the level of incentives.
- Questions were raised as to whether avoided capacity costs should be weighted by the allocation of avoided energy to different resource types.
- The market price for Palo Verde represents the price for a firm product, not a product that varies hour to hour.
- The modeled natural gas pipeline reservation fee if 2-3 times higher than what APS actually incurs.
- Solar DE causes a pronounced double peak during non-summer days, which will affect the types of resources that APS needs to install to manage this load shape. Future storage technologies may positively affect the situation as well.

Creating a Sustainable Solar Market, Chris Yunker, SDG&E

Presentation Summary

Chris Yunker reviewed the challenges the SDG&E has been facing accommodating significant quantities of solar PV resources into the SDG&E electric grid. Mr. Yunker also discussed his plans to modify SDG&E rates to better incentivize solar DE and net metering customer participation and operation.

The following topics summarize the presentation provided by Mr. Yunker.

- SDG&E is creating a market structure that can accommodate market changes and customer choices through the implementation of unbundled services

- SDG&E is planning for 33% renewable energy by 2020
- Solar matches peak today, but will change in the future and SDG&E need price signals to incentivize customers to meet that change
- At 20 percent renewable, SDG&E has surplus during some periods and must sell at a loss
- Need rates and market structure to incentivize flexible capacity
- Testing experimental EV and TOU rates

- Intermittent resources
  - Diversity is not sufficient to manage intermittency of renewable resources
  - Need to incentivize storage
  - Customers can buy storage services from the utility or install it themselves
- Unbundled services
  - Technology will cause customers to "unbundle" their needs
  - Utility must provide the correct unbundled price signals
  - Customers should pay at the correct rate when receiving a service and should be compensated at the correct rate when providing a service
  - Correct pricing should have nothing to do with subsidies needed to achieve policy goals

Stakeholder Comments and Q&A

Stakeholders made the following comments or received the following answers to questions pertaining to the Mr. Yunker's presentation.

- Since things are always changing, how can solutions be developed today? If prices and services are properly unbundled, they are flexible and can adapt to change.
- How do you make sure incentives are at the right level? Incentives and rates should be transparent and unbundled; incentives created through rates are biased.
- Unbundled rates can be too complex for customers to understand. Flat rate options can be offered that incorporate a hedge the customer pays.

The Evolution of Net Metering, Rate Design, and the Utility Business Model, Ron Binz, Public Policy Consulting

Presentation Summary

Ron Binz provided a summary of major trends in rate design for net metering rate design, with a specific focus on regulatory issues. The following topics summarize the presentation provided by Mr. Binz.

- Policy Objectives
  - Encourage solar
  - Diversify supply
  - Reinforce grid
- Rate design issues
  - Correct signal when price = marginal cost

  - But marginal cost doesn't correctly compensate utility
  - Rate structure compromise
  - Complicated when customer is buyer and seller
- Unbundle tariff rate from DE payment (buy-all/sell-all model)
- Real issue is the evolving utility model, not distribution cost recovery under NEM
- Utilities under pressure to change
- Regulation may not be up to the task
- Interviews with utility CEOs
  - Want clear energy policies
  - Little incentive for innovation
  - Want certainty on climate change policy
- Interviews with commissioners
  - Primary focus is rates
  - Open to changing model, but inadequate resources
  - Dissatisfied with process and system
- New regulatory models needed

Stakeholder Comments and Q&A

Stakeholders made the following comments or received the following answers to questions pertaining to the Mr. Binz's presentation.

- Solar has passed break-even threshold with natural gas
- Long-run incremental cost is the most useful indicator for valuing capacity decisions
- Accommodating customer choice and flexibility may require changing regulatory model from lowest cost to highest value

APS Conceptual Solutions, Chuck Miessner, APS

Presentation Summary

Chuck Miessner discussed in very general terms the objectives of APS in modifying its net metering rates and/or solar DE program and outlined a few basic concepts that APS is considering, and then open the floor for discussion. The following topics were discussed by Mr. Miessner.

- APS has not made a decision on solutions
- Potential solutions
  - Rate design concept – better alignment of the value of solar DE with a solar-specific rate
  - Total DE concept – buy-all/sell-all
  - May need to address incentives

Stakeholder Comments and Q&A

The following comments and issues were provided by stakeholders in response to Mr. Miessner's discussion of potential APS solutions.

- Concepts are to align value to costs so there is not subsidization either way
- Buy-all/sell-all correctly captures the exchange. Buy-all/sell-all is different from current end of year true-up.
- Consider offering both buy-all/sell-all and net metering.
- How will grandfathered rate/incentives be transferred to a new homeowner?
- Under buy-all/sell-all, customers do not get to reduce their use, become independent. The customer's net load is the same either way, but it is accounted for differently; the bill would still be credited.
- Customers are not billed at marginal costs, which would result in different rates for different customers and could result in high rates.
- In buy-all/sell-all model, how do you project rates/credits over time? Do they change simultaneously, how often do they need to be reviewed/set? Rates may be changed to remove embedded incentives and administered as a separate tariff.
- One solution under consideration by APS is something similar to the Austin plan.
- Will APS consider eliminating demand charges for schools and churches? That change would make the problem worse.
- Rate fluctuation for DE production makes it difficult to finance DE installations by driving up the cost of finance. Rates change over time now; how much stability is needed—5, 10, 20 years?
- Why is net metering being singled out when other cost shifts are not? Other subsidy issues are well known and have been vetted through the ACC. Net metering and solar DE are not being singled-out, but instead need to be vetted similar to other known subsidies.
- APS should consider sending education material on rates to customers applying for solar hookup.
- Marginal costs of new utility resources are more expensive than embedded cost/rates; solar DE customers should be compensated for avoided marginal costs.
- Is it better for APS for customers to disconnect from the electric system (with appropriate energy production and storage technologies) or continue to be served through net metering? APS would prefer to have customers so long as costs are being recovered.
- Is APS considered offering rates that provide lower levels of reliability? Not in this proceeding.
- Question for financers is what tolerance is needed around rate fluctuation? Answer: Financing takes fluctuations into account and financers can get comfortable with banded cash flow projections.
- In a buy-all/sell-all model, how do you police solar customers from diverting production prior to the meter?
- What are other utilities doing? Austin is considering separate rates for DE export, SDG&E is considering a more highly unbundled rate structure, Idaho Power is considering treating T&D costs as a demand charge, Dominion Power is implementing standby charges.
- How do we know a future facility will be avoided, what happens if future costs are not avoided but credits have been provided to DE customers?

- Does PURPA supersede enforcement of a buy-all/sell-all model; don't customers have the choice to sell only the excess? Under PURPA, excess is sold at avoided cost; size of the customer and DE facility and annual production also affect the determination. Net metering and PURPA are separate rulings.
- Need to consider whether a buy-all/sell-all approach results in tax consequences for DE participants that are different from what would be incurred under a self-serve and net metering approach.

CLOSING FORUM

WORKSHOP SUMMARY

The closing forum provided a recap of the meeting workshops, similar to that provided in this Facilitators Report, but at a lower level of detail. Significant observations of workshops were highlighted, where appropriate. The Closing Forum was conducted by Bob Davis, the Facilitator of the Technical Conference. Because the Closing Forum is essentially a distillation of the information already presented in the preceding sections of this report, no summary of the Closing Forum presentation is provided.

COST-BENEFIT MATRIX

The Cost-Benefit Matrix, containing final input from all interested stakeholders, was reviewed and discussed during the Closing Forum. A copy of the final Cost-Benefit Matrix is provided in the Appendix.

There was discussion about some new methodological categories that the solar stakeholders wanted to add to the matrix. However, the Facilitator suggested that it was too late to add new items because other stakeholders would not have time to respond to these new entries. Instead, the additional items presented by the solar stakeholders were posted as comments on the Cost-Benefit Matrix and were included in the Data Room of the www.solarfuturearizona.com website.

STAKEHOLDER COMMENTS AND Q&A

The following comments, questions and general discussions were posed by the stakeholders during the Closing Forum.

- It would be more accurate to state that SAIC did independent work without input from this group/process. The ACC order said to address both DE costs and benefits and net metering; the APS report does not address net metering. APS staff replied that the Commission directive was to conduct a technical conference. The SAIC report was an initiative by APS included in its process; it was not the process itself. APS staff noted that the utility has expanded this process to include many topics of interest to stakeholders. APS agreed that the SAIC study is not a net metering study; it is a study of DE costs and benefits and is foundational for net metering.
- It was suggested that the language on a slide be clarified to state that rates are designed to recover current costs; that we are not discussing two sets of costs. An APS representative suggested that there are differences in using a future test year compared to a historical test year and that the different methods arrive at different result. The stakeholder clarified that there is an established relationship between costs and billing parameters and differences in methods but that using either method, rates are designed to recover costs during the period the rate is in effect.

- A request was made to organized comments so that it is clearer which views are from APS and which statements are from other stakeholders. Mr. Davis explained that he was attempting to reflect the diversity of perspective in this presentation and that the report would reflect a fuller discussion.
- Since mining entities consume about 10 percent of load, other classes subsidize mines because mines only pay one percent of the RES charge. Has APS looked into whether this is cost shifting? An APS staff member noted that contributions to the RPS adjustor were not looked at in the Navigant study, which looked at rates and cost recovery. The issue has been previously decided by the ACC and is reviewed annually.
- It was noted that DE and EE are somewhat convoluted. An APS staff member acknowledged that APS has similar concerns for EE but many more customers can participate in EE. Because of this there is less shifting. EE load reductions are about 5 percent not 70 percent, as can be the case for DE. This is a smaller magnitude and APS will address this issue in other forums.
- Solar should be treated like other EE measures.
- In discussing the value of DE included in the SAIC study, there is additional incremental value of avoided capacity that should be considered, not just conventional power plant sized blocks.
- What about the inclusion of the cost of carbon starting in 2019 and discussions of solar DE acting as a hedge against natural gas? An APS staff member said the costs were modeled in the SAIC study. Both risk and hedge value must be considered. When a utility adds solar or a conventional plant, there are risks. With a plant, the risks are with both the capital investment and fuel costs. With solar, all the risk is in the capital investment, because there are no ongoing fuel costs. The utility is taking more risk in this capital investment because these costs can change over time as well. For solar, APS is sinking that cost for 40 years, similar to upside down mortgages in AZ.
- Impacts from climate change and water use should also be captured in the risk discussion. An APS staff member replied that these are captured in capacity and fuel risk planning. Costs for solar installations are decreasing; buying solar today locks the utility into a more expensive resource than future costs that are trending lower. If the price goes down tomorrow, this is a financial risk for the utility because it results in an adverse outcome. Businesses have to make choices on how to deal with risks. Similar to homeowners making choices on insurance: you can forego insurance, but this subjects you to the volatility of adverse event and the ensuing financial costs, or you can buy insurance to attenuate that volatility through the cost of the insurance premium. A participant noted that in this case, the risk is to the ratepayer not APS, because the costs are covered in a rate adjustment.
- Suggestion that the wording on slide 33 should say, "PG&E has stated a 25-cent subsidy..." because no study was done.
- Ratepayers have asked APS to develop renewable energy, as referenced in an APS survey posted on the solarfuturearizona.com Website. Suggestion to include a ratepayers' perspective in the cost benefit matrix.

- Suggestion that damage from coal comes to 17.8 cents/kWh (according to studies from Harvard and Yale), with all-inclusive costs at 27 cents/kWh. Over the next few years this issue should be part of the discussion. An APS staff member reflected that externalities and societal benefits are difficult to incorporate in a utility cost-of-service or rate process.
- A slide notes that funds spent in the local economy may have more benefit than funds spent by the utility, should remove "may".
- The SAIC study showed that while only a handful of distribution circuits would be affected, it amounts to one-third of the of planned distribution work and ensuing costs being eliminated, suggesting a larger benefit than was credited.
- The point about customers disconnecting from the grid was not made "tongue in cheek" as suggested by the laughter in the room during the original discussion. The issue is not if customers should disconnect or not, but rather at what value or costs will the customer disconnect.
- Suggested was made to include a customer stakeholder perspective on the cost-benefit matrix. APS commissioned a study that confirmed overwhelmingly that AZ ratepayers support adding renewables even if it's at higher cost.
- The solar stakeholders agreed with Mr. Davis' proposal to post the potential new categories as a separate document and suggested other parties should be free to submit their own views. Other stakeholders noted that they would like to get input from their membership, before deciding.
- An APS representative noted that this is the close of the technical conference but that the record is not closed for additional input for the Commissioners to consider. It remains open for everyone to share new materials with the ACC.
- Will APS be filing in one docket or separate dockets? APS staff said they did not yet know. It was suggested that when APS makes its filing, a separate docket would be opened.

APPENDIX

APPENDIX

The Appendix contains the following Items.

- List of Abbreviations and Acronyms
- Workshop Presentations and Meetings Notes:
    - Opening Forum, February 21, 2013
    - Workshop I: Understanding Rates and Distributed Energy Benefits, March 7, 2013
    - Stakeholder Call, March 14, 2013
    - Workshop II: Resource Planning and Distributed Energy Costs, March 20, 2013
    - Workshop III: SAIC Model and Other Models, April 11, 2013
    - Workshop IV: Other Policy and Valuation Perspectives, May 9, 2013
    - Closing Forum, May 28, 2013
- Stakeholder Alignments and Cost-Benefit Matrix
- Catalog of Website Documents
- List of Registered Participants for the Technical Conference

LIST OF ABBREVIATIONS AND ACRONYMS

ACC	Arizona Corporation Commission
APS	Arizona Public Service Company
Btu	British thermal unit
CC	combined cycle
CCGT	combined cycle generating turbine
C&I	commercial and industrial (customers)
CO_2	carbon dioxide
CPUC	California Public Utility Commission
CT	combustion turbine
DE	distributed energy
DG	distributed generation
E3	Energy+Environmental Economics company
EE	energy efficiency
ELCC	effective load carrying capacity
GHG	greenhouse gases
IOU	investor-owned utility
IREC	Interstate Renewable Energy Council
IRP	integrated resource plan
kWh	kilowatt-hour
LFCR	lost fixed cost recovery mechanism
LMP	locational marginal price
MSEIA	Mid-Atlantic Solar Energy Industries Association
MW	megawatt
MWh	megawatt-hour
NEM	net energy metering
NG	natural gas
O&M	operations and maintenance
PROMOD	generation dispatch and production cost modeling tool
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
R&D	research and development
REC	renewable energy credits
RES	renewable energy standard
RPS	renewable portfolio standard
RIM	ratepayer impact measure
SAIC	Science Applications International Corporation
SDG&E	San Diego Gas & Electric Company
SEIA	Solar Energy Industries Association
SEPA	Solar Electric Power Association
T&D	transmission and distribution
TOU	time-of-use
TRC	total resource cost

WORKSHOP PRESENTATIONS AND MEETING NOTES

Copies of PowerPoint slides and meeting notes are provided on the following pages for each workshop. Larger, letter-sized presentation documents are available on the Technical Conference website (www.solarfuturearizona.com). Meeting notes include summaries of presentations and discussions occurring during each workshop. Meeting notes were composed during the workshop to capture the character of the presentations and discussions, but they do not provide an exact transcription of presentations and discussions. An audio recording of the workshop is available on the Technical Conferences website.

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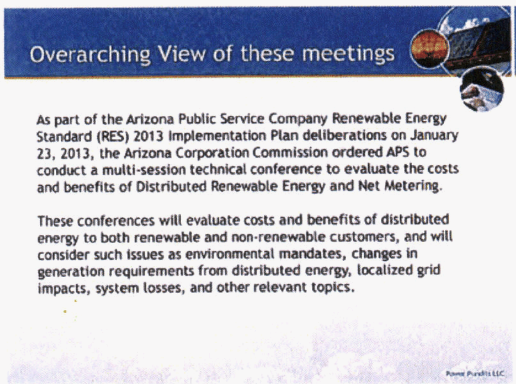
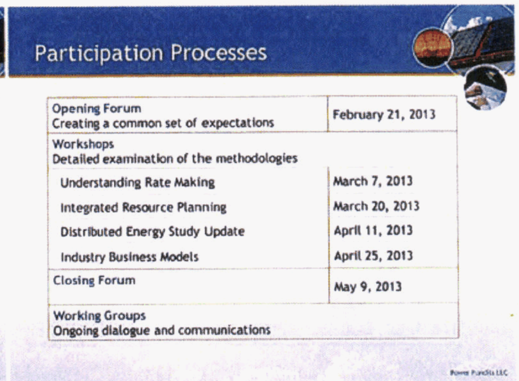
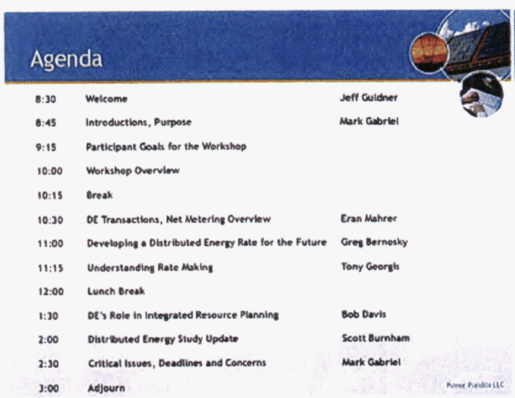
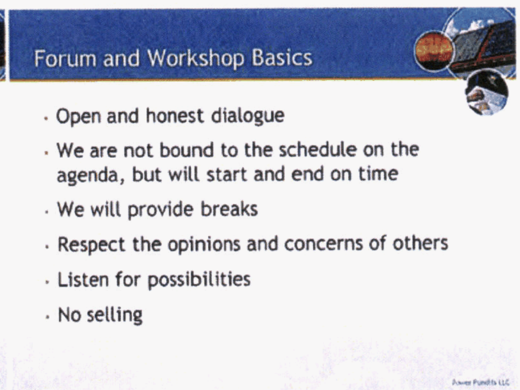
Opening Forum (February 21, 2013)

Presentations









What are we trying to accomplish

- Seeking common ground
- Working to raise level of understanding
- Design and define the future state
- Use this unique opportunity to:
  - Establish a forward vision
  - Build knowledge
  - Address concerns
  - Link needs and desires
  - Inform proposed solution

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Forum and Workshop Goals

- Meet Arizona Corporation Commission expectations
- Create powerful stakeholder collaboration
- Focus activities on education and engagement
- Develop common understanding of issues and options as we work through solutions
- Create an understanding of critical challenges
- Generate continued participation in workshops to help guide the process

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Seeking alignment

Alignment:

The proper positioning or state of adjustment of parts in relation to each other

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Why consensus fails

Consensus seems to be the process of abandoning all beliefs, principles, values and policies. So it is something in which no one believes and to which no one objects.

Margaret Thatcher

Consensus is what many people say in chorus but do not believe as individuals

Abba Eban

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Alignment Model

- Points of view are voiced (reasons for, reasons against, up-sides, down-sides)
- People listen for understanding
- Points of view are considered
- You do not have to *agree* to align; merely recognize you understand and will support
- The team will:
  - **Restate and affirm when alignment is reached**
  - **Make the decision with action steps**
- Once made, all support 100%.

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Words do make a difference

•What does the alignment process look like?
- •Strongly expressing views, opinions and attitudes (no passive/aggressive behavior)
- •Listening for understanding (no observer critics)
- •Pushing, prodding, testing and poking at decisions (if required)
- •Understanding various points of view
- •Aligning and follow through outside of the decision making group
- •Speak up in meeting

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Distributed Energy Transactions,
Net Metering Overview

Eran Mahrer, SEPA

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SEPA
solar electric power association

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Distributed Energy Transactions

Net Metering Overview

February 21, 2013

SEPA solar electric power association

Are we talking about NEM?

Net energy metering (NEM) is a billing mechanism that credits solar system owners for the electricity exported onto the electricity grid.

Under the simplest implementation of net metering, a utility customer's billing meter runs backward as solar electricity is generated and exported to the electricity grid and forward as electricity is consumed from the grid.

What's missing?

Behind the meter "savings" impacts on ratepayer costs, host economics and utility cost recovery

Does "behind the meter savings" have the same impact on the electric distribution system as energy efficiency?

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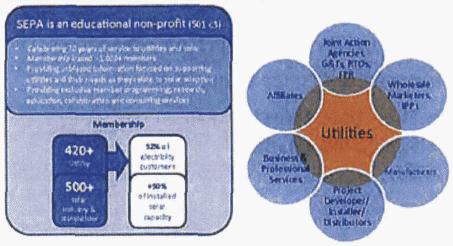
About SEPA



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Perspectives from utilities on DG

Behind-the-meter generation: tensions amplified

Solar DG presents utilities with dramatic issues and unprecedented opportunity...

- Net energy metering
  - Revenue loss (near-term)
  - Rate inequity and overall upward rate pressure
- Customer experience management
  - Satisfaction tied to experience of "going solar"
  - Customers now perceive 'choice' in electricity source, but successful solar demands a strong utility
- *High penetration distributed resources*
  - Distribution grid operational concerns – safety, reliability and cost
  - Resource screening and grid management needs

...with changing customer energy demands and opportunities, regulatory models will require adaptation, both for the utility and the customer

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Solar energy credit and NEM

Today 43 states and over 400 utilities offer some form of net energy metering...

Origin of net metering

- Complex utility procurement
- Poor alignment around customer interests
- Ease of communication

Why net metering "made sense"

- Easily explained to the customer
- Reasonable model at low penetration
- Demonstrated alignment between regulators and customers

...what is the likelihood of every instance offering customers the "right" compensation?

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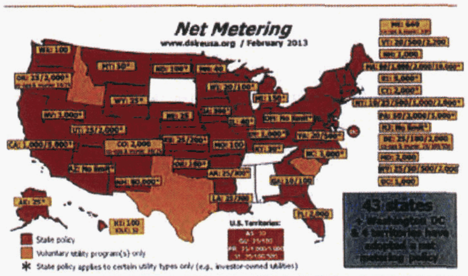
Net-Energy Metering

Most jurisdictions recognize SEC/NEM impacts



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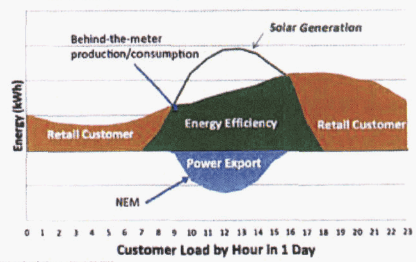
Industry perspective on solar energy credit

Is this really energy efficiency?



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Demand-based rates

Applied to all customers or only solar customers

- Rates with a demand component capture customer peak demand
  - Peak demand is reflective of customer "usage" or "burden" on the distribution system
  - Demand charges can be aligned to recover fixed costs
- Broadly applied to commercial/industrial customers
  - Properly designed, can be applied to all customers or only solar customers

➢ Successfully deployed in conjunction with DG more than any other model to address NEM

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Issues with NEM and SEC

Issues to reconcile under current SEC models

Signals for reevaluating SEC and NEM in the current format

- PV cost declines and upward rate pressure send poor market signal to customers/developers
- Utility cost recovery impacts become significant
- Incentives within net metering may be material but are clearly exposed
- Customers have gained enough sophistication to understand alternatives

Signals from utilities across the country

- SEC and NEM do not allow for fixed cost recovery
  - Operating cost reduction with DG integration may not be as high as value of avoided purchases and system benefits
  - Non-solar ratepayers bear these costs, rate pressure not sustainable
- Decline in asset costs are not transferred to ratepayers supporting deployment

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Camps dividing on addressing NEM

Camp 1	Camp 2			
NEM is fine, don't change it.	NEM needs to be reevaluated.			
	Demand charges	Cost of Services	Value of Solar	Model
One Rate Structure			Two Rate Structures	

Ref. SEPA and CPR DOE Roundtable Dec 2012

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Camp 1 – Voices from the Advocates
NEM is working, don't change it

http://votesolar.org/resources-impacts-of-net-metering-in-california/

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Camp 2 – Reevaluate NEM
Equitable cost distribution and full cost recovery

- Option 1: Demand-based rates
  - Leverage demand/capacity-based rate design to recover fixed costs
- Option 2: Cost of Services
  - Retain single rate but redesign it based on the net cost for the utility to serve the PV customer
- Option 3: Value of Solar (aka Solar Rate or Smart FiT)
  - Treat consumption separately from production

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Cost of Services Approach

- Identify services utilities provide to PV customers
- Identify services PV customers provide to utilities
- Develop repeatable and transparent methods to determine cost for each service
  - Calculate the net cost
  - Determine existing NEM exchange adequacy
- Supports advanced services and variety of customer-side resources
  - Can reflect values including power quality, storage, VAR supports, etc.

➢ Under development in one territory, analytically complex

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Sample list of services
Cost of services approach under development

Service	Customer Cost	Utility Cost
Energy		
Resource Adequacy Capacity		
Ancillary Services		
Grid Management		
Transmission Capacity		
Transmission O&M		
Distribution Station Capacity		
Distribution Line Capacity		
Distribution Voltage Regulation and Reactive Supply		
Distribution O&M		
Interconnection		
Metering, Billing, and Customer Service		
Total		

Net Cost of Service = (Customer Cost) – (Utility Cost)

Ref. SDG&E and Black and Veatch

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Value of Solar Approach
A two rate approach

- Separate consumption transaction from production transaction
- Define value of solar
  - Identify resource value of distributed resource (PV)
  - Develop methods to calculate cost/benefits associated with distributed resource
- Facilitate two customer transitions
  - Bill customers for all consumption using existing rate
  - Credit customers for all production using value of solar

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Value of Solar
Long-term attributes of solar

Value Component	Basis
Avoided Fuel Cost	The cost of natural gas fuel that would have to be purchased for a gas turbine (CCGT) plant operating on the margin to meet electric loads and T&D losses
Plant O&M Cost/benefit	The costs/benefits associated with the operations and maintenance of the CCGT plant
Avoided Generation Capacity Cost	The capital cost of generation to meet peak load and planning margins
T&D Capacity Cost/benefit	The cost/benefit of savings resulting from deferring T&D capacity additions
Avoided Environmental Compliance Cost	The cost to comply with known and defined environmental regulations
Fuel Price Hedge Value	The cost to minimize natural gas fuel price uncertainty
(Solar Penetration Cost)	The additional cost incurred to accept variable solar generation onto the grid

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Aligning around common objectives
Building towards long-term sustainablity

Objectives in designing NEM alternatives

1. Quantify the system value of the distributed solar resource
2. Establish a transaction model that supports solar and customers
3. Maintain transactional and operation simplicity
4. Build a model that allows for DG development and minimizes need for subsidies
5. Maintain reliable recovery of utility costs

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Thank you

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Developing a Distributed Energy Rate for the Future

Greg Bernosky, APS

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Developing a DE Rate for the Future

- Distributed Solar Energy is an option for a greater number of utility customers
  - Reduction of installed costs
  - Customer finance models
  - Federal and state investment credits
  - Utility rate and cash incentives
- More than 250 MW of installed DE is on the APS system

2012 DE growth exceeded 2010 and 2011 combined

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Rates that Match Customer Choices

What's Changing

Customers are producing and consuming energy in new and innovative ways

What's Needed

- Safe and reliable power supply available to all customers when they need it
- Utility rates that recover the cost of infrastructure investments from customers based on services provided
- Modernized utility rate design that manages cost impacts to participant and non-participant customers

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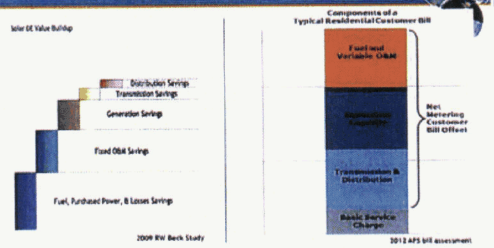
Framing the DE Discussion



Costs and Benefits | **Billing Gaps**

These impacts must be considered in DE rate making

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Rates that Match Customer Choices

How We Can Get There

1. Identify the unbundled costs of service utilities provide and the benefits DE customers create for the system
2. Discuss the role, if any, of incentives or subsidies and make them clear, transparent, and separate from utility rate design
3. Explore how to implement rate design changes to make DE solar sustainable through new rate schedules, evaluating the current net metering rules, and/or the transaction for acquiring DE energy

This technical conference is a critical step in reaching these goals

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Status of the DE Discussion

- 2009 RW Beck Study on DE Operating Impacts and Valuation
  - Early foundation for evaluation of DE penetration and costs
- 2012 Navigant Study of Net Metering and Distributed Energy Cross-Subsidies
  - Identified three distinct types of cross-subsidies for DE
    - Utility and Fed/State cash incentives
    - Retail rate offset and bill credit
    - Net metering compensation
  - Intended to describe the issue of costs as a lead-in to the discussion of valuing DE costs and benefits

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Rates and Ratemaking

Tony Georgis, NewGen Strategies & Solutions

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Agenda

- Overview of APS and Market
- Rate Making Principles and Best Practices
- Overview of Rate Making Process
- APS Current Costs, Revenues and Rate Structures
- Questions and Answers

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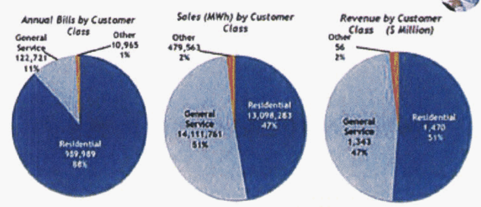
APS Energy Revenue and Customer Profiles



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APS Service Functions

Major Service Functions

- Generation (Power Plants)
- Transmission and Distribution (Wires)
- Customer Service

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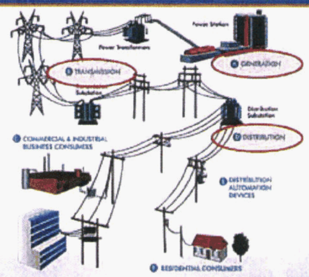
APS Utility Operations



Functions:

- **Generation**
- **Transmission**
- **Distribution**
- **Customer (Accounting, Billing, etc.)**

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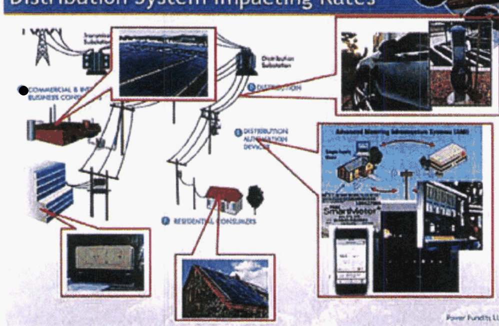
Growing Stress On and Dynamic Use of Distribution System Impacting Rates



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Ratemaking Principles and Best Practices

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Ratemaking Principles & Best Practices

James Bonbright, *Principles of Public Utility Rates*

1) Practical: simple, understandable, acceptable
2) Uncontroversial as to interpretation
3) Should meet revenue requirements
4) Should provide stable revenues
5) Should provide stable rates
6) Fairness among customer classes
7) Avoidance of undue discrimination
8) Should be economically efficient

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Ratemaking Principles & Best Practices

Rate Objectives & Inherent Tension

- Equity and Fairness
- Meet Revenue Requirements
- Low Rates
- Social Issue Responsiveness
- Consumption Pattern Modification
- Simplicity and Understandability
- Adherence to Laws and Regulations

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Overview of APS Rate Making Process

Rate Making Process

Determine the revenue requirement of the utility — **STEP 1: REVENUE REQUIREMENT DETERMINATION**

Functionalize costs and services (production, transmission, distribution, etc.)
Classify costs (demand, energy, customer costs, etc.)
Allocate costs among customer classes — **Step 2: UNBUNDLED COST OF SERVICE**

Design rates — **Step 3: RATE DESIGN**

Step 1: Revenue Requirement

Definition:

Total costs of providing electricity to customers in various rate classes to be recovered through rate revenue

- Test Year:
  - Utility basis
  - Known and Measurable Adjustments
- Calculates the costs a customer / customer class imposes on the system
- For each customer class, rates should generate revenues equaling the class revenue requirement
- Foundation of a Cost of Service study

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Step 2: Unbundled Cost of Service

- How much it costs the utility to provide services to different types of customers
- Functionalization of Costs
  - Generation
  - Transmission
  - Distribution
  - Customer

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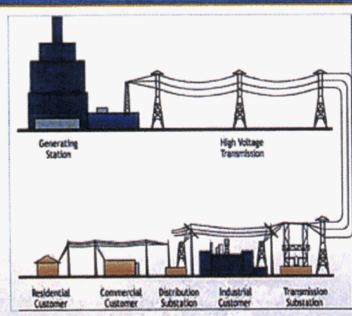
Customer Class Differences



Step 2: Unbundled Cost of Service

Classification of Costs

- Demand-related
- Energy-related
- Customer-related
- Direct Assignments

Step 2: Unbundled Cost of Service

Allocation Factors

- Customer service characteristics
  - Level of effort to bill/service
  - Number of customers
- Customer usage characteristics
  - Contribution to system peak
  - Total Energy used

Step 2: Unbundled Cost of Service

Customer Classes

- Similar demand and energy requirements
- Similar electric facilities requirements
- Served at similar voltage levels
- Similar uses of electricity
- Similar customer service needs

Step 3: Rate Design

- Charges to collect revenue requirement
- Rate design objectives for each customer class:
  - Cost-based
  - Understandable to customers
  - Sends proper pricing signals to customers
  - Maintain revenue stability to support the ongoing operations of the utility

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Step 3: Rate Design

- Typical Rate Components:
  - Customer Charge - A flat per customer or per meter charge that is not based on the total amount of energy consumption
  - Demand Charge (in kW) - A charge based on customer peak demand during a given month
  - Energy Charge (in kWh) - A volumetric charge based on energy consumed
  - Fuel or Power Cost Recovery Charge (in kWh) - A volumetric charge based on energy consumed specific to the recovery of fuel, fuel related costs and purchased power

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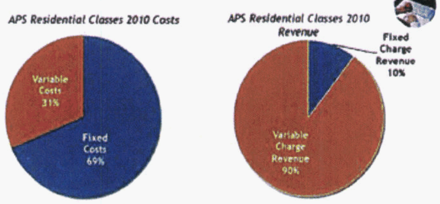
APS Residential Cost Structure vs. Revenue Collections



APS Residential Costs/Revenue (2010 COS)

	Costs	Revenue
Fixed	$ 1,096,389,015	$ 152,895,323
Variable	$ 499,689,339	$1,317,238,054

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APS Current Cost and Rate Structure

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Aligning Rates and Structures with Cost to Serve

Fixed versus Variable Costs

- Fixed Costs
  - Non-fuel Generation
  - Distribution
  - Customer
  - Transmission
- Variable Costs
  - Fuel

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Summary of Upcoming Rate Workshop

- Development of Revenue Requirements
- Demonstrate Cost of Service process
- How to develop rates
- Demonstrating integrated relationship and impacts of policy, costs, rates and incentives (price signals)
- Work through specific distributed energy ratemaking

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Integrated Resource Planning and Distributed Energy

Bob Davis, nFront Consulting

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Integrated Resource Planning (Definition)

"Electric utility resource planning process that treats demand and supply resources on a consistent and integrated basis."

National Energy Policy Act of 1992

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Integrated Resource Planning (Definition)

- Arizona Administrative Code, Title 14, Chapter 2, Article 7 generally describes Resource Planning as follows:
  - Resource planning means integrated supply and demand analyses, comparing a wide range of resource options that promote fuel and technology diversity, while reliably serving the demand for electric energy services
  - Includes the delivered costs for all resources: capital, operating, maintenance, fuel, decommissioning costs, environmental compliance, system integration, backup capacity, transmission delivery, and integration costs for intermittent resources
  - Plans for reducing environmental impacts related to air emissions, solid waste, and other environmental factors, and for reducing water consumption
  - Specific targets for renewable and distributed energy resources
  - Considers energy efficiency and DSM programs
  - Achieves reasonable long-term total cost and effectively manages uncertainty and risks

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Impact of Distributed Energy on Integrated Resource Planning

- DE can have an impact on how electric utilities operate and plan for resources
  - Can reduce utility capacity costs by delaying or avoiding the need to build or procure future resources
  - Can reduce utility energy costs by altering the operation of generating resources and purchases
  - Cost reductions may be offset by certain cost increases:
    - Need for firming capacity
    - Increased need for operating reserves
    - Delayed implementation of other high-efficiency resources

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Evaluation of DE Impacts on Integrated Resource Planning

Cost Effect	Planning Analyses
Avoided Capacity Costs Savings from avoided or deferred generation expansion costs	- Forecast DE implementations and nameplate capacity reductions - Adjust DE load impacts for system losses (increase to be consistent with supply resources) - Evaluate coincidence of DE with electric system peak demands - Evaluate level of dependable capacity attributable to DE - Evaluate DE impact on utility expenditures for generation expansion

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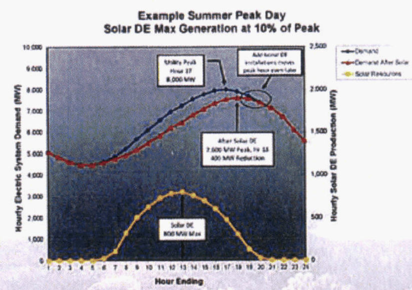
How Does DE Impact Utility Loads



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Evaluation of DE Impacts on Integrated Resource Planning

Cost Effect	Planning Analyses
Avoided Energy Costs Savings from avoided costs of generation commitment and dispatch	- Multi-year simulation of hourly generation dispatch with and without DE load impacts - Compute difference in costs between cases
Other Cost Impacts Potential increased cost of generation dispatch and/or need for additional reserves	

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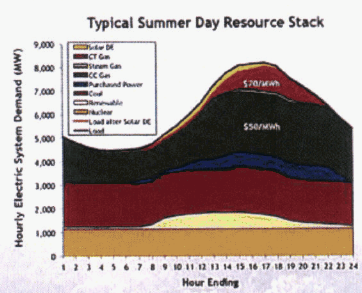
Example Energy Costs Avoided by DE



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Recommended Topics for IRP Workshop - March 20, 2013

- Review forecast of DE penetrations and load shapes
- Review utility load shapes and coincidence of DE load shapes
- Estimate utility costs that can be avoided through implementation of DE resources
  - Review current IRP for APS
  - Review analyses used by utilities to assess avoided costs
  - Example computation of avoided capacity costs
  - Example computation of avoided energy costs

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Refresh of 2009 RW Beck PV Study

Scott Burnham, SAIC

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What was the 2009 RW Beck Study?

- Study sought to understand DE's potential operating value/ impacts across utility in the long-run (2015 & 2025)
  - Technologies assessed: PV, Solar Water Heater, Commercial Daylighting
  - Developed initial solar penetration forecast
- Stakeholder collaboration shaped methodology for measuring DE value by avoided costs or deferred investments
  - 35 companies, universities, associations, and national labs participated
- Hypothetical scenarios provided range of possible DE values depending on how actual, future deployment might occur

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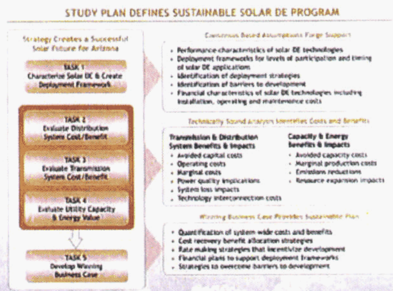
Methodology



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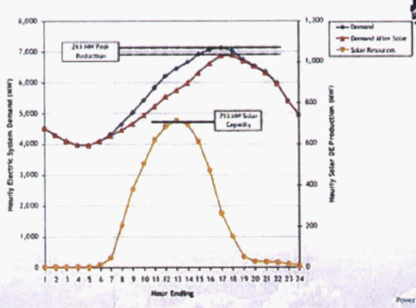
Example of Results from 2009 [TO BE UPDATED]



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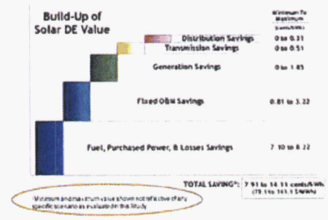
Value Ranges in 2025 (2009 Study)



- Maximum numbers do NOT correspond to high case value
- Ranges include some academic scenarios (e.g. What if all residential and commercial customers on a single feeder install single-axis tracking PV?)

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Need for 2013 Update

- Key value drivers have changed
  - Load and resource forecasts - reduced
  - Natural gas, CO_2 prices - lower
  - DE adoption rates - higher
- Assess current DE forecast with actual experience instead of conceptual penetration
  - >20,000 systems installed-to-date vs. 1,000 in 2008
  - Geographic deployment data
  - Focus on fixed-tilt solar PV

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Data Used for 2013 Update

- Same 2015 and 2025 timeframe retained from original study
- Same methodology from 2009 Study stakeholder process

2012 Integrated Resource Plan	Resource planning model runs with and without solar generation for 2015 and 2025
2012 Q4 Long Range Forecast	Marginal peak electricity costs versus overall average costs for 2015 and 2025
DE scenario forecasts for 2015 and 2025	Feeder Load Profiles and Forecasts
APS 10 Year Transmission Plan	DE penetration by distribution feeder, feeder standards
Residential and Commercial Solar Installation Counts	Transmission capital improvement forecasts
Energy and demand line losses (average)	Distribution capital improvement forecasts
Solar system characterization (technology, production factors, orientation, etc.)	Existing applicable feeder analysis results with and without solar generation
Annual hourly PV output characteristics for typical residential and commercial system	Fuel price forecast and financial assumption data - carrying costs, escalations rates, etc.
Recent PV Integration Cost Study (Black & Veatch)	
Solar PV interconnect agreement (restrictions on feedback to system)	

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Participation Processes

Opening Forum Creating a common set of expectations	February 21, 2013
Workshops Detailed examination of the methodologies	
Understanding Rate Making	March 7, 2013
Integrated Resource Planning	March 20, 2013
Distributed Energy Study Update	April 11, 2013
Industry Business Models	April 25, 2013
Closing Forum	May 9, 2013
Working Groups Ongoing dialogue and communications	

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Next Steps

- www.solarfuturearizona.com will be populated
- Material from today's presentation will be posted this evening
- Questions will be collated and matched to upcoming workshops

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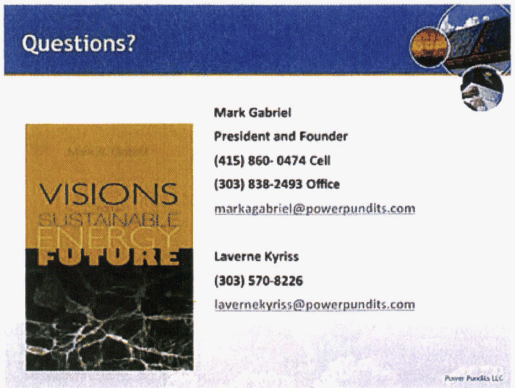
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Meeting Notes

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Decision and Process Advisement in Energy and Water

TO: APS Opening Forum Participants

FROM: Power Pundits LLC

RE: Opening Forum

DATE: February 18, 2013

In response to an order from the Arizona Corporation Commission related to its 2013 Renewable Energy Standard Implementation Plan, Arizona Public Service Company hosted an opening forum February 21, 2013 at its Ocotillo site in a multi-session technical conference to evaluate the costs and benefits of distributed renewable energy and net metering. The sessions are designed to evaluate these costs for all customers—both those who have access to distributed energy and those who do not. The sessions will explore such issues as environmental mandates, changes in generation requirements resulting from adding distributed energy to the generation stack, localized grid impacts, system losses and other relevant topics. APS engaged Mark Gabriel and his team at Power Pundits LLC to lead, moderate and manage this technical conference.

Seventy-five stakeholders registered for the opening forum. Of these, 60 attended in person and 9 listened via a phone connection. The opening forum was designed to bring together stakeholders holding a wide range of perspectives, experiences and levels of technical knowledge into a group setting to help define a common set of expectations for this process. Copies of the presentation slides are available at www.solarfuturearizona.com.

Opening Forum Goals
Jeff Guldner, APS senior vice president, opened the session by outlining APS' goals and critical challenges as they seek ways to reliably and responsibly add an increasing amount of distributed energy to the utility's generation mix.

Mark Gabriel next outlined the goals of this process, provided a brief overview of the upcoming sessions and previewed the agenda for the day. He highlighted that in this process we would seek to develop a common understanding of the issues and options as we work toward solutions, create an understanding of the critical challenges facing all participants—both the stakeholders and the utility, and that we would work to meet the expectations of the Arizona Corporation Commission.

Stakeholder Goals

Gabriel next asked participants to share their goals for the workshops, as well as issues, concerns and aspirations. Topics raised during this segment include:

- Costs and benefits; holistic look; best practices; how wide or narrow; inclusion of storage value; inclusion of fossil and nuclear subsidies
- Data sources for study; use of industry studies; need for a data-driven process
- Rate fairness and equity; rate stability; long term impacts; best value;
- Study methodology and assumptions; stakeholder agreement to these
- Stakeholder data access
- Inadequacy of current rate design to accommodate future DE
- Role of the Navigant study
- Resource cost effectiveness; RIM test as the measure; impacts on non-participants
- Level playing field; no disadvantages to any market segment
- Need to drive innovation; need for creative new business models

Parking Lot (related issues)

Several related issues and concerns were also raised for consideration in this technical workshop, including:

- Need for future research and development, including pilot studies, new approaches
- Creating a sustainable future for DE in AZ including sustained demand
- Qualified solar installer program
- Consumer education when purchasing DE system
- Impacts from load following generation
- Military market penetration assistance
- Arizona Corporation Commission concerns on costs/rate impacts/transparency (seeing what you're paying for); Commission involvement in this process; how to get output to ACC; following where ACC is leading
- Including the value of storage in the full cost/benefit analysis

National Perspective

Eran Maher, vice president, Strategy and Research, Solar Energy Power Association, kicked off the technical presentations by providing an overview of distributed energy transactions and net metering across the nation. He helped set the stage by pointing out that solar distributed generation presents utilities with dramatic issues and unprecedented opportunity, noting that with changing customer energy demands and opportunities, regulatory models will require adaptation—both for the utility and for the customer. Maher outlined how the various net metering programs across the nation have evolved and the difficulties that have ensued. He discussed a number of issues that have arisen and will need to be reconciled under the current solar energy credit and net energy metering models. Maher outlined the varying perspectives as well as outlined some potential ways to ensure equitable cost distribution and full cost recovery. He reminded participants that resource choices have impacts to consumers, and that even with equal long term value, near term impacts to rate payers are not always equal. Maher summed up by encouraging participants to keep these objectives in mind in designing net metering alternatives:

- Quantify system value of the distributed solar resource
- Establish a transaction model that supports solar and customers
- Maintain transactional and operating simplicity
- Build a model that allows for distributed generation development and minimizes the need for subsidies
- Maintain reliable recovery of utility costs

Maher responded to several stakeholder questions and comments about which costs should be included and the different approaches in which that is occurring today across the nation.

APS Perspective

Greg Bernosky, Renewable Energy Manager, APS, next discussed APS' need to develop a distributed energy rate for the future. He outlined the changing ways in which customers are producing and consuming electricity and how APS must respond to these changes while maintaining a safe and reliable power supply, recovering appropriate infrastructure investment costs and modernizing its rate design to manage cost impacts to renewable energy participants and non-participants alike. Bernosky described the need to have rates that match customer choices and identified three tasks that must be completed to get there:

- Identifying the unbundled costs of service the utility provides and the benefits DE customers create for the system
- Discussing the role, if any, of incentives or subsidies and making them clear, transparent and separate from utility rate design
- Exploring how to implement rate design changes to make DE sustainable through new rate schedules, evaluating current net metering rules and/or the transaction for acquiring distributed energy.

Bernosky summed up by reviewing APS' past DE and net metering studies, noting that the recent Navigant study was intended to describe the cost issues as a lead in to the discussion of valuing DE costs and benefits that are being explored in this process.

Bernosky received numerous questions and suggestions. Topics included:

- Using a real residential bill as we work through the issues
- Changes to the E32 rate structure and the resulting impacts to customers
- How the distributed rate adoption plan will be developed and implemented
- The view that net metering is not broken and doesn't need to be fixed
- The solar industry was not involved in setting this approach; suggest the Beck study refresh be the starting point
- Will the output from this process be a comprehensive cost/benefit study?

Rate Making

Tony Georgis, with NewGen Strategies and Solutions, provided an overview of rates and rate making principles to introduce participants to the elements that are included in the rate making process. He began by reviewing the APS energy revenue and customer profiles, noting that while 88 percent of the bills are issued to residential consumers in the APS service territory, these customers consume 47 percent of the electricity and provide 51 percent of the revenue. Commercial customers make up the portion of the mix. Georgis reviewed the basic utility functions, outlined eight rate-making principles and discussed the inherent tensions in rate objectives. He walked participants through the three basic steps in rate making:

- Revenue requirement determination
- Unbundled cost of service determination
- Rate design development

Georgis wrapped up by discussing the need to align rates and rate structures with the costs to serve. He noted that the cost structure for APS residential customers is broken into 31 percent variable costs and 69 percent fixed costs. APS currently recovers these costs by collecting 90 percent of its revenues based on a variable charge (per kWh of power used) and 10 percent of its revenue based on a fixed charge. Georgis received numerous questions on the specifics of the revenue requirements and cost of service elements as well as the discrepancy between how costs are categorized (fixed and variable) and how revenues are collected.

Integrated Resource Planning

Bob Davis, nFront Consulting, covered the role of distributed energy in integrated resource planning. He noted that distributed energy can have an impact on how utilities operate and plan for resources. Distributed resources can reduce capacity costs by delaying or avoiding the need to build or procure future resources. They can reduce energy costs by altering the operation of the generation fleet and power purchases. However, he noted, these reductions can be offset by other cost increases, such as additional need for firming capacity and operating reserves or delaying plans for other high-efficiency resources. He discussed how distributed energy impacts a utility's load shape and how this impacts the utility's plan for needed capacity. Davis reviewed how distributed energy can help a utility avoid energy costs and highlighted that these topics will be further explored in the upcoming workshop.

Davis responded to a question about environmental costs and how those are factored in.

DE Impacts Study

Scott Burnham, SAIC, provided an overview of the 2009 study by RW Beck to understand the operating values and impacts of distributed energy on APS' distribution, transmission and system planning activities. The study considered photovoltaics, solar water heating and commercial daylighting technologies and developed an initial solar penetration. Bernham noted that stakeholders collaborated in shaping the methodologies for measuring DE value by avoided costs or deferred investments. The study used a range of scenarios to provide possible DE values for various future deployment options. Burnham outlined the need for updating the study. Several drivers, including load and resource forecasts, natural gas prices and distributed energy adoption rates, have changed since 2008. The updated study will also be able to assess the current DE forecast with actual experience instead of the conceptual penetration rates used in the 2009 study. He noted that today, APS has 20,000 systems installed compared to the 1,000 installed in 2008. Burnham wrapped up by explaining that the "Refresh" Study will use the same 2015 and 2025 timeframes, and the same methodology from the 2009 study stakeholder process. Burnham also listed the key study data inputs that will be used in the Refresh Study.

Burnham received numerous questions and suggestions on technical elements, including:

- Suggest various natural gas pricing schemes be used; cheap gas may disappear; additional environmental regulations may affect fuel/plants
- Concern that the Refresh Study will not consider single axis tracking technology; installation of these systems is on the rise
- Request that Scott Burnham be at the next workshop to interact with stakeholders so they can help inform the model inputs and values and the resulting costs and benefits
- Request a discussion on the various scenarios that will be run
- Concern that solar water heating technology is not being included in Refresh study

Next Steps

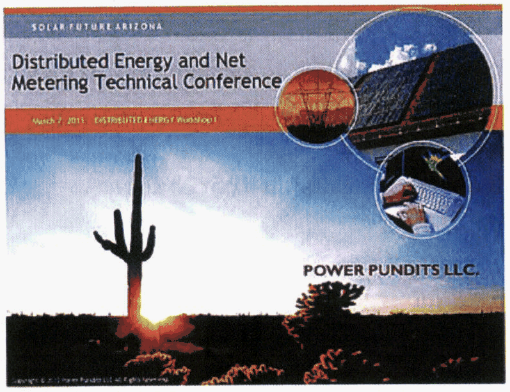
Greg Bernosky responded to a number of additional questions and comments about the Refresh Study and its role in APS' decision process about how to best integrate distributed energy into its resource portfolio and how to fairly and equitably set rates for its service. Stakeholders requested adjustments to the future agendas to allow for time to discuss additional study approached and suggested that additional study work needs to be done. They questioned the time pressure for this technical conference, requested participation in developing the data needs and asked who gets to determine which study approached are used. Some questioned the need for the Rates and IRP workshops, saying the focus should be on study methodology choices. A stakeholder wanted to know if we would discuss cost shifts in the Rates workshop. Another stakeholder objected to the Navigant report because it was based on hypothetical, and not actual, customer data.

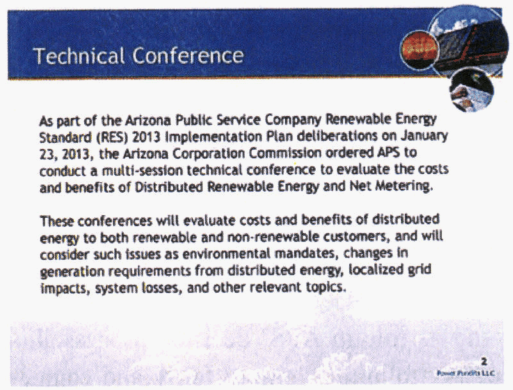
Workshop Wrap Up

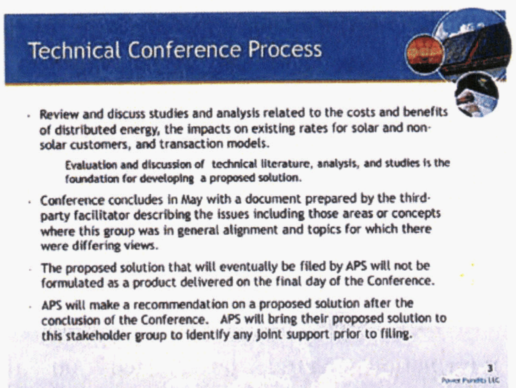
Mark Gabriel wrapped up the day by thanking everyone for their enthusiasm, reminding participants of the upcoming workshop dates and that information would be posted on the www.solarfuturearizona.com website. He committed to developing updated agendas for the upcoming workshops to address as many of the concerns and issues raised during this session as possible and getting those posted next week.

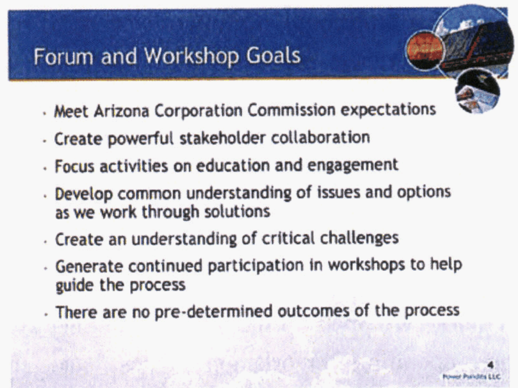
Workshop I (March 7, 2013)

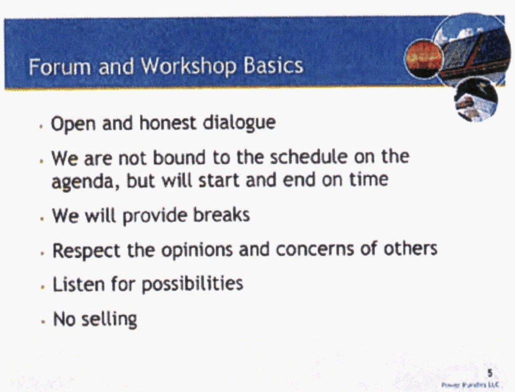
Presentations

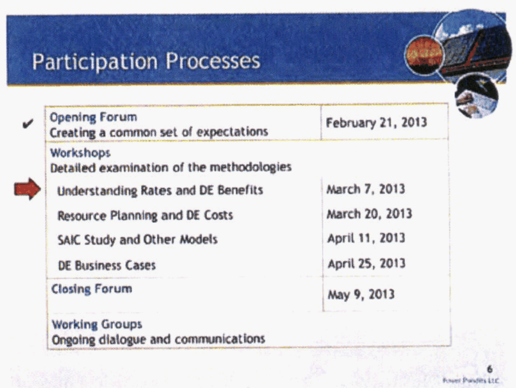












Agenda

- Responses to questions
- Review of Opening Forum Issues
- Revision of Workshop Agendas and Content
- Opportunities for alignment
- DE Benefits from 2009 Study
- Fundamentals of Utility Ratemaking
- APS Rates Overview
- Next Steps

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Agenda

8:30	Welcome	*Mark Gabriel*
9:00	Opportunities for Alignment	Mark Gabriel
10:00	DE Solar System or Cost Benefits From 2009 R.W. Beck Study	Round Table
11:00	Break	
11:15	Round Table Continued	
12:00	Lunch Break	
1:00	Fundamentals of Utility Rate Making	*Tony Georgis*
3:00	APS Rates Overview and Impact of DE Solar	*Chuck Miessner*
4:30	Recap	*Mark Gabriel*
5:00	Adjourn	

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Open Items from Previous Session

- Data Access?
  - Information will be provided on www.solarfuturearizona.com following written requests except where data is restricted*
- How will results of these meetings be communicated?
  - Online at www.solarfuturearizona.com
  - Creation of a facilitator's report
- Use techconf@aps.com for questions and comments

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Stakeholder Goals, Aspirations, Issues

Issue	Workshop I Rates and Benefits	Workshop II Resource Planning/ Costs	Workshop III SAIC Study and Other Models	Workshop IV DE Business Cases
Costs and Benefits	X	X	X	X
Transparency of Costs	X	X	X	X
Role of Navigant Study?		X	X	
RIM/Non Participant Impacts	X	X		
Net Metering Impacts	X	X	X	
Statewide, holistic cost/benefit analysis				
Subsidies for fossil and nuclear		X		
Additional industry studies			X	
Assumptions and methodologies	X		X	

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Stakeholder Goals, Aspirations, Issues

Issue	Workshop I Rates and Benefits	Workshop II Resource Planning/ Costs	Workshop III SAIC Study and Other Models	Workshop IV DE Business Cases
Best practices	X	X	X	X
Impacts of load following generation	X	X		
Rate Balancing	X			
Moving power between accounts	X	X		
Do what's good for Arizona	X	X	X	X
Long term rate impacts	X			X
Rules of the road	X			X
Level playing field	X			X
Current rate design	X			
Results into action				X

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Stakeholder Goals, Aspirations, Issues

Issue	Workshop I Rates and Benefits	Workshop II Resource Planning/ Costs	Workshop III SAIC Study and Other Models	Workshop IV DE Business Cases
RES Compliance	X	X	X	X
Bringing Process to ACC				X
Communications of results				X
Consumer education			X	X
Creative new business models			X	X
Military market opportunities				X
R&D and innovation			X	X
Sustainable future for Arizona	X	X	X	X
Qualified solar installer program				
Value of storage in analysis	X		X	X

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What are we trying to accomplish

- Seeking common ground
- Working to raise level of understanding
- Design and define the future state
- Use this unique opportunity to:
  - Establish a forward vision
  - Build knowledge
  - Address concerns
  - Link needs and desires
  - Inform proposed solution

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Seeking Alignment

Alignment:

The proper positioning or state of adjustment of parts in relation to each other

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Alignment Model

- Points of view are voiced (reasons for, reasons against, up-sides, down-sides)
- People listen for understanding
- Points of view are considered
- You do not have to *agree* to align; merely recognize you understand and will support
- The team will:
  - **Restate and affirm when alignment is reached**
  - **Make the decision with action steps**
- Once made, all support 100%.

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Words do make a difference

- **What does the alignment process look like?**
  - *Strongly expressing views, opinions and attitudes (no passive/aggressive behavior)*
  - Listening for understanding (no observer critics)
  - Pushing, prodding, testing and poking at decisions (if required)
  - *Understanding various points of view*
  - Aligning and follow-through outside of the decision making group
  - Speak up in meeting

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Alignments

- Transparency is critical
- *Subsidies for all fuel sources should be considered*
- Rates need to provide fairness
- Additional studies besides Beck should be considered
- There should be a level playing field between DE technologies
- Current rate design may not be compatible with DE
- Solar represents an important economic development issue in Arizona
- Consumer education is important
- There is a need for continued innovation and new approaches

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Alignments

Working definition for the purposes of this technical conference

Net Metering:

The **rate offset** = DE generation that serves a portion of the customer's overall consumption

and

The **bill credit** = DE generation that exceeds the customer's consumption and is carried forward as a credit against future bills

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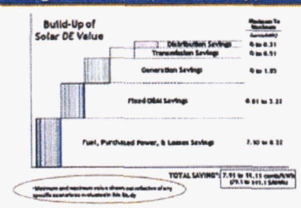
DE Solar System and Cost Benefits from the 2009 R.W. Beck Study

Joni Batson, SAIC

Value Ranges in 2025 (2009 Study)



- **Maximum numbers do NOT correspond to high case value**
- **Ranges include some academic scenarios (e.g. What if all residential and commercial customers on a single feeder install single-axis tracking PV?)**

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Data Used for 2013 Update

- **In addition to the data being used in the study update, what other data should be considered?**

- 2012 Integrated Resource Plan
- 2012 Q4 Long Range Forecast
- DE scenario forecasts for 2015 and 2025
- APS 10 Year Transmission Plan
- *Residential and Commercial Solar Installation Counts*
- Energy and demand line losses (average)
- Solar system characterization (technology, production factors, orientation, etc.)
- Annual hourly PV output characteristics for typical residential and commercial system
- Recent PV Integration Cost Study (Black & Veatch)
- Solar PV interconnect agreement (restrictions on feedback to system)
- Resource planning model runs with and without solar generation for 2015 and 2025
- Marginal peak electricity costs versus overall average costs for 2015 and 2025
- Feeder Load Profiles and Forecasts
- DE penetration by distribution feeder, feeder standards
- Transmission capital improvement forecasts
- Distribution capital improvement forecasts
- Existing applicable feeder analysis results with and without solar generation
- Fuel price forecast and financial assumption data - carrying costs, escalations rates, etc.

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2013 Update

- Key value drivers have changed
  - Load and resource forecasts - reduced
  - Natural gas, CO_2 prices - lower
  - DE adoption rates - higher
- *Assess current DE forecast with actual experience instead of conceptual penetration*
  - 14,000 PV systems installed-to-date vs. 400 in 2008
  - Geographic deployment data
  - Focus on fixed-tilt solar PV

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Methodology

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Additional data considerations - SEIA

- Market price mitigation
- Benefits from southwest or west facing orientations of fixed arrays
- Grid security benefits
- Fuel hedge value
- Environmental compliance savings
- Reliability benefits
- Environmental savings (like water)
- Avoided RPS wholesale purchases

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Additional data considerations

- Same 2015 and 2025 timeframe retained from original study
- What are the methodological concerns for the R.W. Beck Study?
- What other studies should be considered?
  - Crossborder
  - Austin Model
  - Others?

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Fundamentals of Utility Ratemaking

Tony Georgis

NewGen Strategies & Solutions

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Agenda

- Recap of February 21, 2013 overview
- Rate Making Process
  - Policy Objectives & Strategy
  - Revenue Requirements
  - Cost of Service (COS)
  - Rate Design

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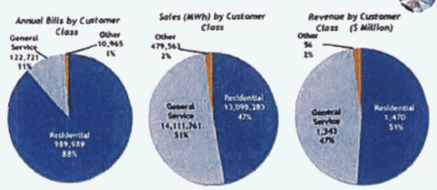
APS Energy Revenue and Customer Profiles



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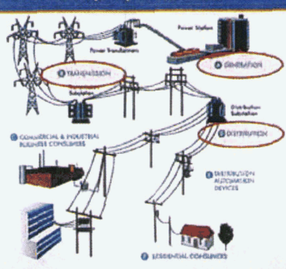
APS Utility Operations



Functions:

- Generation
- Transmission
- Distribution
- Customer (Accounting, Billing, etc.)

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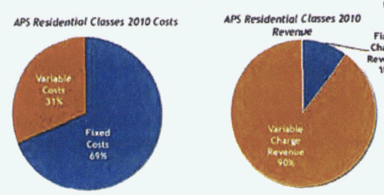
APS Residential Cost Structure vs. Revenue Collections



APS Residential Costs/Revenue (2010 COS)

	Costs	Revenue
Fixed	$ 1,096,389,015	$ 152,895,323
Variable	$ 499,689,339	$1,317,238,054

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Ratemaking Principles & Best Practices

James Bonbright, *Principles of Public Utility Rates*

1) Practical: simple, understandable, acceptable
2) Uncontroversial as to interpretation
3) Should meet revenue requirements
4) Should provide stable revenues
5) Should provide stable rates
6) Fairness among customer classes
7) Avoidance of undue discrimination
8) Should be economically efficient

Ratemaking Principles & Best Practices

Rate Objectives & Inherent Tension

- Equity and Fairness
- Meet Revenue Requirements
- Low Rates
- Social Issue Responsiveness
- Consumption Pattern Modification
- Simplicity and Understandability
- Adherence to Laws and Regulations

Rate Making Process

Steps in the Ratemaking Process

STEP 1	Determine the revenue requirement of the utility	REVENUE REQUIREMENT DETERMINATION
Step 2	Functionalize costs and services (production, transmission, distribution, etc.)	COST ALLOCATION
Step 3	Classify costs (demand, energy, customer costs, etc.)	
Step 4	Allocate costs among customer classes	
Step 5	Design rates	RATE DESIGN

Step 1: Revenue Requirement

Definition:

Total costs of providing electricity to customers in various rate classes to be recovered through rate revenue

- Test Year:
  - Utility basis
  - Known and Measurable Adjustments
- Calculates the costs a customer / customer class imposes on the system
- For each customer class, rates should generate revenues equaling the class revenue requirement
- Foundation of a COS study

Step 1: Revenue Requirement

Revenue Requirement Components:

- Reasonable operating expenses
- Other cash or non cash expenses
- Cost of capital
- Taxes
- Fair return on investment
- Less other non-rate income sources

Step 1: Revenue Requirement

Definition - Known and Measurable Adjustments:

Financial and/or operating adjustments to actual historical utility performance. Adjustments are based on proven changes that have occurred or are expected to occur in the near future.

Step 1: Revenue Requirement

Known and Measurable Adjustments

Examples include:

- Load Changes
- Extraordinary Capital Projects
- Financing
- Re-organization, Re-structuring
- Power Supply

Step 1: Revenue Requirement

Account
APS Operations
Generation
Transmission
Distribution
Customer Accts/Sales
Metering
Billing
Meter Reading
Subtotal Operations
Depreciation
Income / Other Taxes
Less Other Revenues (Fees)
Return on Rate Base*
Total Revenue Requirement

* Rate Base is separately calculated and represents the regulated profit for APS

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Step 1: Revenue Requirement - Rate Base and Rate of Return

- Rate Base
  - Total net plant / assets value (gross plant less Depreciation)
  - Working capital
  - Minor adjustments, inventories, reserves
- Rate of Return
  - Weighted average cost of capital (WACC)
  - Interest rate(s) on debt and approved return on equity
  - Multiply rate base by rate of return to calculate regulated aggregate return

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Step 1: Revenue Requirement - Rate Base and Rate of Return

Return on Rate Base Example

- Weighted Average Cost of Capital (WACC)
  - A regulated utility is allowed to earn a return on its investment. The return included in the revenue requirement is the Rate Base multiplied by a percentage rate of return (ROR).

Example:

Rate Base = $100 Million
Allowed ROR = 10%
Allowed Return =$10 Million per year

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Step 2: Functionalize Costs

STEP 1	Determine the revenue requirement of the utility	REVENUE REQUIREMENT DETERMINATION
Step 2	Functionalize costs and services (production, transmission, distribution, etc.)	COST ALLOCATION
Step 3	Classify costs (demand, energy, customer costs, etc.)	
Step 4	Allocate costs among customer classes	
Step 5	Design rates	RATE DESIGN

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Step 2: Functionalize Cost of Service

- How much it costs the utility to provide services to different types of customers
- Functionalization of Costs
  - Generation
  - Transmission
  - Distribution
  - Customer Service

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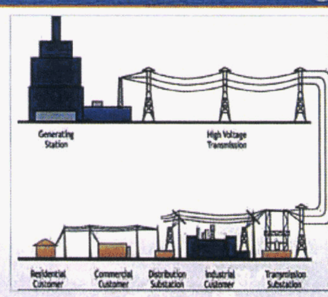
Functionalizing Costs: Customer Class Differences



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APS Functionalized Revenue Requirement

Account	Total	Unit Cost
Operations		
Generation	1,862,836,955	$0.0673/kWh
Transmission	129,300,830	$0.0047/kWh
Distribution	555,609,579	$0.0201/kWh
Customer	168,154,729	$12.47 Cust/Month
Regulatory Assets	70,899,407	$0.0026/kWh
System Benefit	82,056,532	$0.0030/kWh
Total Revenue Requirement	2,868,858,032	$0.1036/kWh

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Step 3: Classify Costs within Functions

STEP 1	Determine the revenue requirement of the utility	REVENUE REQUIREMENT DETERMINATION
Step 2	Functionalize costs and services (production, transmission, distribution, etc.)	COST ALLOCATION
Step 3	Classify costs (demand, energy, customer costs, etc.)	
Step 4	Allocate costs among customer classes	
Step 5	Design rates	RATE DESIGN

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Step 3: Classification of Costs

Classification of Costs

- Demand-related (Fixed Cost)
- Energy-related (Variable Cost)
- Customer-related (Fixed Cost)
- Direct Assignments (Typically Fixed Cost)

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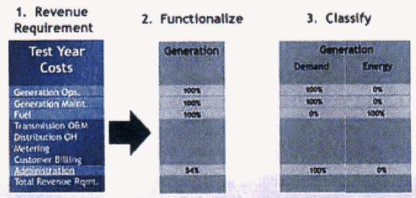
Step 3: Classification of Costs

Classifying Generation Function Costs



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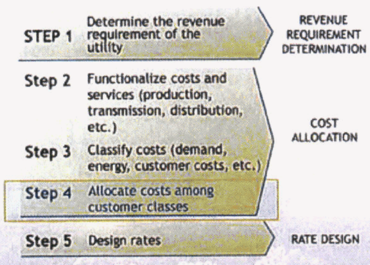
Step 4: Allocate Costs to Customers



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Step 4: Allocate Costs

Allocate Costs to Customer Classes

- Residential
- Commercial
- Industrial

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Step 4: Allocate Costs

Why Have Different Customer Classes?

- Similar demand and energy requirements
- Similar electric facilities requirements
- Served at similar voltage levels
- Similar uses of electricity
- Similar customer service needs

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Step 4: Allocation of Costs to Customer Classes

Allocation Factors: Customer

- Customer service characteristics
  - Level of effort to bill/service
  - Number of customers
- Customer usage characteristics
  - Contribution to system peak
  - Total Energy used

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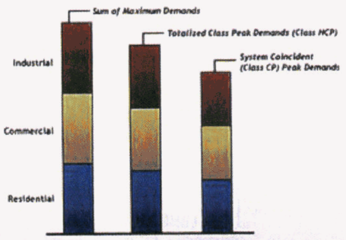
Concept of Coincidence and Diversity



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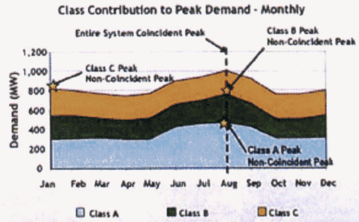
Class Non-Coincident Peak Compared to Contribution to System Coincident Peak

Allocation Factors: Demand



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Examples of Demand Cost Allocation Methods (Summary of Results)

Demand Cost Allocation Percentages	Class A	Class B	Class C	Total
1 CP Method	47.00%	29.00%	24.00%	100.0%
4 CP Method	47.60%	26.60%	25.80%	100.0%
12 CP Method	42.60%	27.40%	30.00%	100.0%
1 NCP Method	44.65%	28.84%	26.51%	100.0%
12 NCP Method	41.80%	28.90%	29.30%	100.0%
AED Method	43.88%	28.66%	27.46%	100.0%
Range	41.80 – 47.60%	26.60 – 29.00%	24.00 – 30.00%	
Ratio, High/Low	1.14	1.09	1.25	

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APS Cost of Service Results

Classification	All Residential	E-30/32 G.S. 0-100kW	E-32 G.S. 401+kW
Demand	$936,684	$251,775	$149,958
Customer	$188,920	$26,966	$745
Variable/Energy	$526,794	$156,176	$140,656
Total	$1,652,398	$434,917	$291,359

Classification	All Residential	E-30/32 G.S. 0-100kW	E-32 G.S. 401+kW
Demand	57%	58%	52%
Customer	11%	6%	0%
Variable/Energy	32%	36%	48%
Total	100%	100%	100%

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APS Cost of Service by Customer Class

Residential	
E-12 - Standard	498,537,692
ET-1 & ET-2 - TOU	837,220,510
ECT-1 & ECT-2 - TOU w/Demand	260,320,151
General Service	
E-20 - Church Rate	4,672,720
E-30, E-32 (0 -100 kW)	420,561,114
E-32 (101-400 kW)	287,341,213
E-32 (401-3000 kW)	283,243,879
E-34 (3000+ kW)	78,257,874
General Service - TOU	
E-30, E-32 - TOU (0 -100 kW)	3,555,210
E-32 - TOU (101-400 kW)	5,133,903
E-32 - TOU (401-3000 kW)	21,054,655
E-35 - TOU (3000+ kW)	110,302,566
Other (Irrigation, Lighting, etc.)	58,656,547
Grand Total	**$2,868,858,032**

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Preparing for Step 5: Rate Design - Cost Curves

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Applying the Cost of Service Results: Development of Cost Curves

Cost of service yields:

- Fixed and variable costs by function (generation, transmission, distribution, customer)
- Classified costs by function (demand, energy, customer)
- Unbundled cost of service by rate class
- Using this information, create cost curves for each rate class

Cost curves graphically illustrate the Cost of Service expressed on a $/kWh basis for a customer over a range of consumption profiles.

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Development of Cost Curves

Example Residential Cost of Service indicates:

$6,500,000 or 81% of costs incurred to serve the residential class is fixed

Only $1,500,000 or 19% are variable

Effective average cost to the customer is heavily dependent on the amount of energy used compared to the customers maximum demands (Load Factor)

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Development of Cost Curves

Cost of Service expressed on a $/kWh basis for a fictional residential class

Demand Related:	$16.67 per kW
Energy Related:	$0.015 per kWh
Customer Related:	$20.83 per customer per month
Total Cost of Service:	$0.080 per kWh

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Developing Cost Curves

Monthly Load Factor	Monthly Peak kW	Monthly kWh	Cost of Demand	Cost of Energy	Cost of Customer Service	Total COS	Total COS $/kWh
10%	1.0	73	$16.67	$1.10	$20.83	$38.60	$0.53
20%	1.0	146	$16.67	$2.19	$20.83	$39.69	$0.27
30%	1.0	219	$16.67	$3.29	$20.83	$40.79	$0.19
40%	1.0	292	$16.67	$4.38	$20.83	$41.88	$0.14
50%	1.0	365	$16.67	$5.48	$20.83	$42.98	$0.12
60%	1.0	438	$16.67	$6.57	$20.83	$44.07	$0.10
70%	1.0	511	$16.67	$7.67	$20.83	$45.17	$0.09
80%	1.0	584	$16.67	$8.76	$20.83	$46.26	$0.08
90%	1.0	657	$16.67	$9.86	$20.83	$47.36	$0.07
100%	1.0	730	$16.67	$10.95	$20.83	$48.45	$0.07
Unit Cost			$16.67	$0.015	$20.83		

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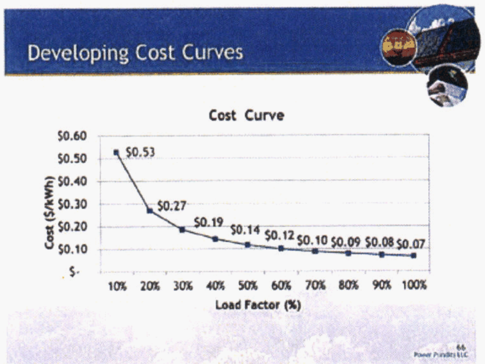
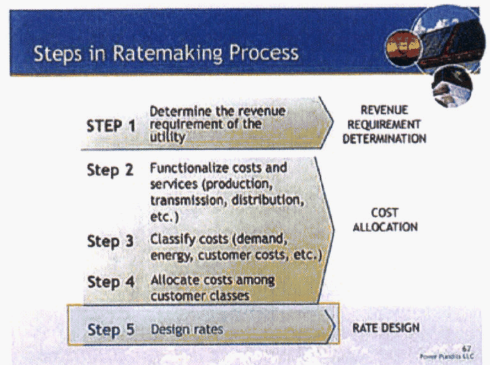

Developing Cost Curves
Cost Curve
$0.60
$0.50
$0.40
$0.30
$0.20
$0.10
$-
Cost ($/kWh)
$0.53
$0.27
$0.19
$0.14
$0.12
$0.10
$0.09
$0.08
$0.07
10% 20% 30% 40% 50% 60% 70% 80% 90% 100%
Load Factor (%)
66


Steps in Ratemaking Process
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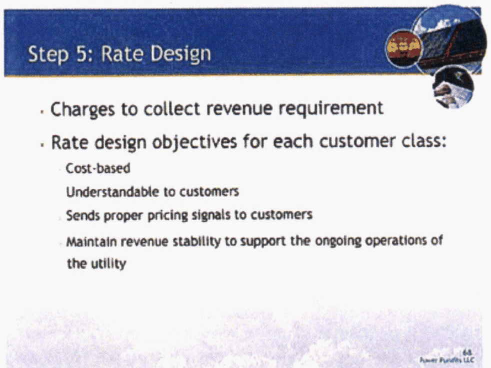
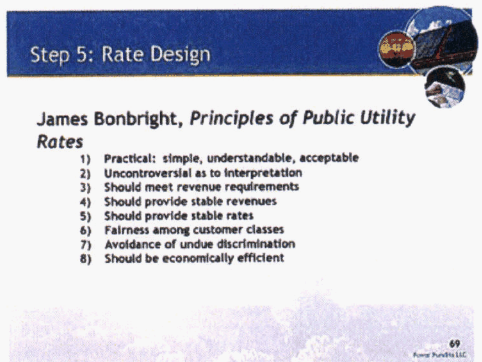
COST ALLOCATION
Step 5 Design rates
RATE DESIGN
67


Step 5: Rate Design
Charges to collect revenue requirement
Rate design objectives for each customer class:
Cost-based
Understandable to customers
Sends proper pricing signals to customers
Maintain revenue stability to support the ongoing operations of the utility
68


Step 5: Rate Design
James Bonbright, Principles of Public Utility Rates
1) Practical: simple, understandable, acceptable
2) Uncontroversial as to interpretation
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4) Should provide stable revenues
5) Should provide stable rates
6) Fairness among customer classes
7) Avoidance of undue discrimination
8) Should be economically efficient
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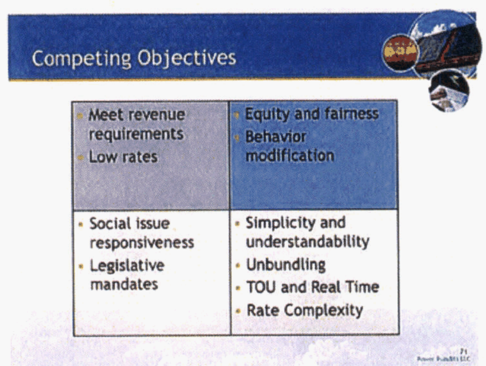
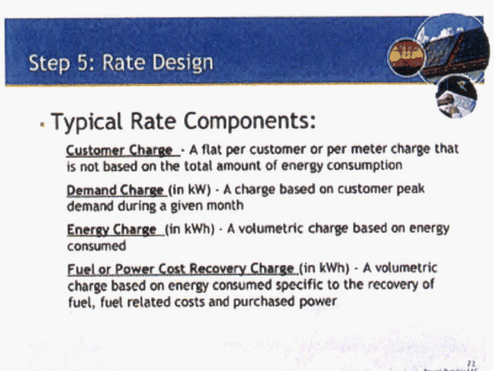
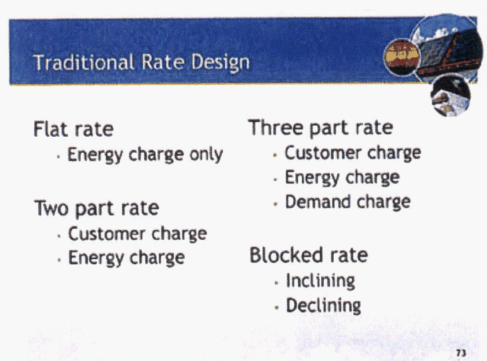
Step 5: Rate Design
Objectives of Rate Making:
Cost of service
What the public wants
Fairness to all consumers
Marginal costs
Price as a resource control measure
Market forces and elasticity
Simplicity vs. complexity
Price as a taxing measure
Price as a welfare measure
Quality of service
Difference among communities' concerns
Cost of Service
Rate Making
Policy
70


Competing Objectives
Meet revenue requirements
Low rates
Equity and fairness
Behavior modification
Social issue responsiveness
Legislative mandates
Simplicity and understandability
Unbundling
TOU and Real Time
Rate Complexity
71


Step 5: Rate Design
Typical Rate Components:
Customer Charge - A flat per customer or per meter charge that is not based on the total amount of energy consumption
Demand Charge (in kW) - A charge based on customer peak demand during a given month
Energy Charge (in kWh) - A volumetric charge based on energy consumed
Fuel or Power Cost Recovery Charge (in kWh) - A volumetric charge based on energy consumed specific to the recovery of fuel, fuel related costs and purchased power
72

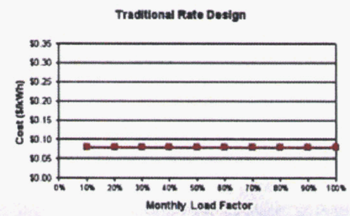

Traditional Rate Design
Flat rate
Energy charge only
Two part rate
Customer charge
Energy charge
Three part rate
Customer charge
Energy charge
Demand charge
Blocked rate
Inclining
Declining
73

Flat Rate

Energy only

- Exceedingly simple
- Not normally applicable to larger customer classes
- Generally used for special rates
- Example:
  - $0.08/kWh

Flat Rate



Two Part Rate

Customer/Energy

- Generally for residential and small commercial
- Customer charge intended to collect fixed customer costs
- Minimum bill provisions can mimic customer charge

Energy/Demand

- Generally for larger general service customers
- Promotes efficient use of system (high load factor)

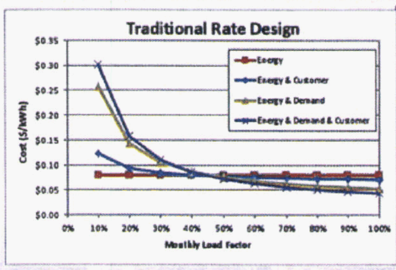
Examples

- $20.83/mo. and $0.065/kWh
- $0.03/kWh and $16.67/kw -mo.

Three Part Rate

- Customer/energy/demand
- Allows for specific rate design to collect based on each component of cost

Three Part Rate

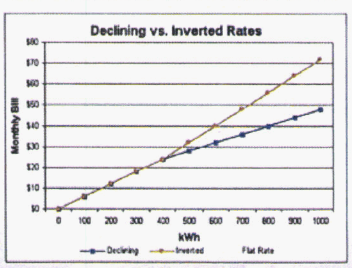


Blocked Rates

- Varying rate based on level of consumption
- Can be applied to energy, demand or both
- Declining block
  - Consumption above a certain level is a lower rate
  - Intended to reward larger (higher consumption) customers
- Inverted or inclining block
  - Consumption above a certain level is a more expensive rate
  - Intended to promote conservation (penalize larger users)

	Declining	Inverted
0-400 kWh	$0.06	$0.06
above 400 kWh	$0.04	$0.08

Blocked Rates



Subsidization

Inter and Intra Class Subsidization

Intra-class Subsidization (within a customer class):

- Individual customers within a single customer class that over / under pay their true cost of service. Overpaying customers subsidize the underpaying customers.
- Example: high load factor commercial customers pay more than cost of service to subsidize lower load factor customers

Inter-class Subsidization (across customer classes):

- Customers of one class that pay more than their true cost of service to benefit another class that is paying less than their true cost of service.
- Example: Commercial customer class is paying more than the cost of service to subsidize residential customers who are paying less than their cost of service

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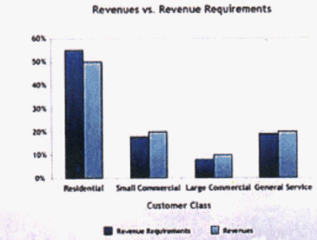
Interclass Subsidization Example



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Intraclass Subsidization: Residential Class Example

	Existing Rate	COS Rate
Customer Charge	$5/mo.	$12/mo.
Energy Charge	$0.07/kWh	$0.06/kWh

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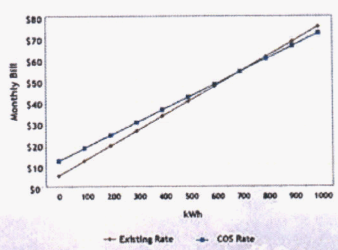
Intraclass Subsidization Residential Class Example



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APS Current Cost and Rate Structure

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Aligning Rates and Structures with Cost to Serve

Fixed versus Variable Costs

- Fixed Costs
  - Non-fuel Production
  - Distribution
  - Customer
  - Depreciation
  - Taxes
- Variable Costs
  - Fuel

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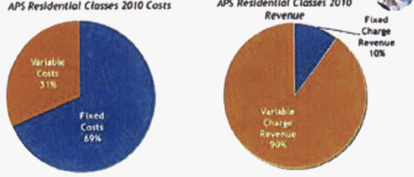
APS Residential Cost Structure vs. Revenue Collections



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	Costs	Revenue
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Variable	$ 499,689,339	$1,317,238,054

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APS Current Unbundled Rate Structure

Unbundled Components of an APS Energy Electric Bill

- Basic Service Charge
  - Customer Account Charge
  - Metering
  - Meter Reading
  - Billing
- Energy Charge
  - System Benefits Charge
  - Transmission Charge
  - Delivery Charge
  - Generation Charges
    - Res Inclining Block
    - Commercial Declining Block (after 30% LF)
    - Time-of-Use (for TOU Classes only)
    - Seasonality
- Demand Charge
  - Demand Class Transmission Charge
  - Delivery Charges
  - By Service Level (Secondary, Primary, Transmission)
  - Declining Block
  - Time-of-Use (for TOU Classes only)

Note:
Typical bill condensed to "bundled" charges of:
-Customer
-Energy
-Demand (where applicable)

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APS Current Rate Structure - Adjustments

Adjustments

- Renewable Energy Standard
- Power Supply Adjustment
- Transmission Cost Adjustment
- Environmental Improvement Surcharge
- Demand Side Management Adjustment
- Lost Fixed Cost Recovery
- Taxes

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APS Rates Overview and the Impact of DE Solar

Chuck Miessner, APS

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APS Rates Overview and the Impact of DE Solar

- APS major rate classes
- Billing elements and charge types
- APS specific rate designs and DE bill savings
- Conceptual discussion of cost-shifting "billing gap" issue
- Navigant study
  - Purpose
  - Method and results
  - Comments and critiques

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APS Major Retail Rates

Rate	Customers	GWh	Revenue ($M)
Residential			
Inclining Block (IB)	479,264	29%	32%
TOU-E	423,193	51%	50%
TOU-D	102,066	20%	17%
Class Total	1,004,522	13,247	$1,591
Business			
XS	101,321	11%	16%
Small	17,113	19%	24%
Medium	4,281	24%	24%
Large	980	26%	22%
XS,S,M,L TOU	446	3%	3%
XL	31	6%	4%
XL-TOU	39	14%	6%
Class Total	124,211	14,087	$1,328

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Charge Types

Fixed — Basic Service Charge (BSC)
Per day, regardless of usage or maximum draw
Total days in the billing month

Variable — Energy
Per kWh
Total usage in a month

Fixed — Demand
Per kW
Maximum draw in any hour during the month

A Fixed charge is one that is designed to recover fixed costs and doesn't vary with kWh usage

Mixed — Hours Use
Per kWh
Two tiers of energy charges. First tier charge is higher and acts like an embedded demand charge as long as customer's total energy consumption is greater than the first tier block.

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Residential
Inclining Block Rate (IB)Charge types: BSC, energy

	Summer Charge	Winter Charge	Potential DE Savings
BSC ($/Day)	$ 0.285	$ 0.285	No
Energy ($/kWh)			
0-400 kWh	$ 0.09687		Yes
401-800 kWh	$ 0.13817		Yes
800-3000 kWh	$ 0.16167		Yes
> 3000 kWh	$ 0.17257		Yes
all kWh		$ 0.09417	Yes
Adjustors			
$/kWh	$ 0.00945	$ 0.00945	Yes
Capped $/Month	$ 3.83	$ 3.83	?

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Residential
TOU Energy Rate (TOU-E)Charge types: BSC, energy

	Summer Charge	Winter Charge	Potential DE Savings
BSC ($/days)	$ 0.556	$ 0.556	No
Energy ($/kWh)			
On-Peak (12-7)	$ 0.24477	$ 0.19847	Yes
Off-Peak	$ 0.06118	$ 0.06116	Yes
Adjustors			
$/kWh	$ 0.00945	$ 0.00945	Yes
Capped $/Month	$ 3.83	$ 3.83	?

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DE Bill Savings vs Utility Cost Savings
Residential IB, TOU-E Rates

Billing Elements	Cost Type	Charge Type	DE Bill Savings	Utility Cost Savings
Base Rates:				
Metering and Billing	Fixed	Monthly		
Delivery	Fixed – NCP	kWh	X	
Transmission	Fixed – CP	kWh	X	
System Benefits	Fixed	kWh	X	
Generation - Capacity	Fixed – CP	kWh	X	Partial
Generation - Fuel and variable O&M	Variable	kWh	X	X
Adjustments:				
Renewable Energy Standard	Fixed	kWh, Capped		
Power Supply Adjustor	Variable	kWh	X	X
DSM Cost Adjustment	Fixed	kWh	X	
Environmental Improvement Surcharge	Fixed	kWh	X	
Federal Transmission Cost Adjustment	Fixed	kWh	X	
Lost Fixed Cost Recovery	Fixed	%	X	
Taxes and Government Fees:				
Regulatory Assessment Fee	Variable	%	X	NA
Franchise Fee	Variable	%	X	NA
Sales Taxes	Variable	%	X	NA

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Residential
TOU Demand Rate (TOU-D)
Charge types: BSC, demand, energy

	Summer Charge	Winter Charge	Potential DE Savings
BSC ($/days)	$ 0.556	$ 0.556	No
Energy ($/kWh)			
On-Peak (12-7)	$ 0.08867	$ 0.05747	Yes
Off-Peak	$ 0.04417	$ 0.04107	Yes
Demand($/On-Peak kW)	$ 13.500	$ 9.300	Low
Adjustors			
$/kWh	$ 0.00945	$ 0.00945	Yes
Capped $/Month	$ 3.83	$ 3.83	?

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DE Bill Savings vs Utility Cost Savings
Residential TOU-D Rates

Billing Elements	Cost Type	Charge Type	DE Bill Savings	Utility Cost Savings
Base Rates:				
Metering and Billing	Fixed	Monthly		
Delivery	Fixed – NCP	kW, kWh	Low	
Transmission	Fixed – CP	kWh	X	
System Benefits	Fixed	kWh	X	
Generation - Capacity	Fixed – CP	kW	Low	Partial
Generation - Fuel and variable O&M	Variable	kWh	X	X
Adjustments:				
Renewable Energy Standard	Fixed	kWh, Capped		
Power Supply Adjustor	Variable	kWh	X	X
DSM Cost Adjustment	Fixed	kWh	X	
Environmental Improvement Surcharge	Fixed	kWh	X	
Federal Transmission Cost Adjustment	Fixed	kWh	X	
Lost Fixed Cost Recovery	Fixed	%	X	
Taxes and Government Fees:				
Regulatory Assessment Fee	Variable	%	X	NA
Franchise Fee	Variable	%	X	NA
Sales Taxes	Variable	%	X	NA

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Business
XS Rate (energy) Charge types: BSC, energy

	Summer Charge	Winter Charge	Potential DE Savings
BSC ($/days)	$ 0.672	$ 0.672	No
Energy ($/kWh)			
Tier 1	$ 0.13537	$ 0.11769	Yes
Tier 2	$ 0.07427	$ 0.05658	Yes
Adjustors			
$/kWh	$ 0.00660	$ 0.00660	Yes
$/kWh or	$ 0.009575	$ 0.009575	?
Capped $/Month	$ 142.25	$ 142.25	

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DE Bill Savings vs Utility Cost Savings
XS Business Customer E-32 XS rate

Billing Elements	Cost Type	Charge Type	DE Bill Savings	Utility Cost Savings
Base Rates:				
Metering and Billing	Fixed	Monthly		
Delivery	Fixed – NCP	kWh	X	
Transmission	Fixed – CP	kWh	X	
System Benefits	Fixed	kWh	X	
Generation - Capacity	Fixed – CP	kWh	X	Partial
Generation - Fuel and variable O&M	Variable	kWh	X	X
Adjustments:				
Renewable Energy Standard	Fixed	kWh, Capped		
Power Supply Adjustor	Variable	kWh	X	X
DSM Cost Adjustment	Fixed	kWh	X	
Environmental Improvement Surcharge	Fixed	kWh	X	
Federal Transmission Cost Adjustment	Fixed	kWh	X	
Lost Fixed Cost Recovery	Fixed	%	X	
Taxes and Government Fees:				
Regulatory Assessment Fee	Variable	%	X	NA
Franchise Fee	Variable	%	X	NA
Sales Taxes	Variable	%	X	NA

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Business
Medium Rate (small rate is same design)
Charge Types: BSC, demand, energy, hours use energy

	Summer Charge	Winter Charge	Potential DE Savings
BSC ($/days)	$ 1.324	$ 1.324	No
Energy ($/kWh)			
Tier 1 (27% LF)	$ 0.09884	$ 0.08378	?
Tier 2	$ 0.06091	$ 0.04586	Yes
Demand ($/kW)			
Tier 1 (0-100)	$ 10.235	$ 10.235	No
Tier 2	$ 5.385	$ 5.385	?
Adjustors			
$/kW	$ 1.781	$ 1.781	?
$/kWh	$ 0.00133	$ 0.00133	Yes
Capped $/Month	$ 142.25	$ 142.25	?

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DE Bill Savings vs Utility Cost Savings
S,M Business Customer E-32 S, E-32 M rates

Billing Elements	Cost Type	Charge Type	DE Bill Savings	Utility Cost Savings
Base Rates:				
Metering and Billing	Fixed	Monthly		
Delivery	Fixed – NCP	kW, kWh	Low	
Transmission	Fixed – CP	kW	Low	
System Benefits	Fixed	kWh	X	
Generation - Capacity	Fixed – CP	Hours Use	?	Partial
Generation - Fuel and variable O&M	Variable	kWh	X	X
Adjustments:				
Renewable Energy Standard	Fixed	kWh, Capped		
Power Supply Adjustor	Variable	kWh	X	X
DSM Cost Adjustment	Fixed	kW	Low	
Environmental Improvement Surcharge	Fixed	kWh	X	
Federal Transmission Cost Adjustment	Fixed	kW	Low	
Lost Fixed Cost Recovery	Fixed	%	X	
Taxes and Government Fees:				
Regulatory Assessment Fee	Variable	%	X	NA
Franchise Fee	Variable	%	X	NA
Sales Taxes	Variable	%	X	NA

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Business
Large Rate
Charge Types: BSC, demand, energy

	Summer Charge	Winter Charge	Potential DE Savings
BSC ($/days)	$ 1.627	$ 1.627	No
Energy ($/kWh)	$ 0.05517	$ 0.03804	Yes
Demand ($/kW)			
Tier 1	$ 21.149	$ 21.149	No
Tier 2	$ 14.267	$ 14.267	Low
Adjustors			
$/kW	$ 1.781	$ 1.781	Low
$/kWh	$ 0.00133	$ 0.00133	Yes
Capped $/Month	$ 142.25	$ 142.25	?

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Business
XL Rate
Charge Types: BSC, demand, energy

	Charge	Potential DE Savings
BSC ($/days)	$ 3.828	No
Energy ($/kWh)	$ 0.03665	Yes
Demand ($/kW)	$ 18.649	Low
Adjustors		
$/kW	$ 1.717	Low
$/kWh	$ 0.00133	Yes
Capped $/Month	$ 1,000.00	?

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DE Bill Savings vs Utility Cost Savings
L, XL Business Customer E-32 L, E-34, E-35 rates

Billing Elements	Cost Type	Charge Type	DE Bill Savings	Utility Cost Savings
Base Rates:				
Metering and Billing	Fixed	Monthly		
Delivery	Fixed – NCP	kW	Low	
Transmission	Fixed – CP	kW	Low	
System Benefits	Fixed	kWh	X	
Generation - Capacity	Fixed – CP	kW	Low	Partial
Generation - Fuel and variable O&M	Variable	kWh	X	X
Adjustments:				
Renewable Energy Standard	Fixed	kWh, Capped		
Power Supply Adjustor	Variable	kWh	X	X
DSM Cost Adjustment	Fixed	kW	Low	
Environmental Improvement Surcharge	Fixed	kWh	X	
Federal Transmission Cost Adjustment	Fixed	kW	Low	
Lost Fixed Cost Recovery	Fixed	NA	NA	
Taxes and Government Fees:				
Regulatory Assessment Fee	Variable	%	X	NA
Franchise Fee	Variable	%	X	NA
Sales Taxes	Variable	%	X	NA

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Cost Equity Test for DE

Utility Cost Savings		Bill Savings
Marginal savings in utility costs as a result of DE that are reflected in rates	=	Bill Savings from DE participants. Includes bill credits from excess generation.

Key Point
If a DE participant causes utility cost savings commensurate with their bill savings - then there is no adverse impacts on rates or on other customers.

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Potential Cost Shift "Billing Gap"

Utility Cost Savings		Bill Savings
Marginal savings in utility costs as a result of DE that otherwise would be reflected in rates	<	Bill Savings for DE participants. Includes bill credits from excess (export) DE solar generation.

Key Point
If DE results in higher bill savings than utility cost savings a "billing gap" will result which shifts the unrecovered costs to non-participating customers and increases rates.

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Potential Billing Gap - Summary

Class	Total Customers	GWh	DE Customers	Potential Billing Gap
Residential				
IB	479,264	29%	5,047	Higher
TOU-E	423,193	51%	8,680	Higher
TOU-D	102,066	20%	643	Lower
Class Total	1,004,522	13,247	14,370	
Business				
XS	101,321	10%	153	Higher
S	17,113	18%	229	Medium
M	4,281	23%	163	Medium
L	980	25%	84	Lower
XS,S,M,L TOU	446	3%	7	Lower
XL	31	6%	0	Lower
XL-TOU	39	14%	1	Lower
Class Total	124,211	14,087	637	

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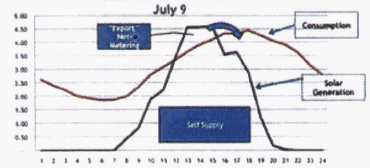
Self Supply versus Net Metering

Residential TOU-E Customer
July 9



Key Point
The Billing Gap is predominantly a rate design issue.
Net Metering contributes by extending the Billing Gap to the nighttime load as well as the daytime load and seasonally to other months.

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LFCR Mechanism
lost fixed cost recovery mechanism

DE Bill Savings

Billing Gap

Utility Cost Savings

LFCR
will increase rates between rate cases
Remaining Cost Shift
will increase rates at next rate case

Key Points The LFCR...
- *does not solve the cost shifting issue.*
- *only changes the timing of when the rate subsidy will occur.*
- *partially addresses the recovery of fixed costs for DE customers, but not which customers pay for this recovery.*

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Navigant Study: Net Metering Bill Impacts and Distributed Energy Subsidies

- Purpose and Scope of the Study
- Methods, Inputs, and Assumptions
- Summary of Results
- Questions and Stakeholder Comments

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Navigant Study - Scope

- Describe the potential for cost shifting and rate impacts of DE
- Conceptually evaluate this equity issue with representative cases from major rate classes and DE participants using current rates and costs
- Assess the compatibility of several of APS's predominant rate designs for residential and small and medium business customers with a rapidly growing level of DE

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Navigant Study - Out of Scope

- A societal cost-benefit test
- An integrated resource plan or resource test
- An impact study on utility finances or earnings
- A rate impact evaluation solely of net metering
- A long-range projection of impacts
- A quantification of the cost shifting impacts for all 14,000 DE (PV) customers

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However...

- Both utility cost savings and DE bill savings will increase over time
  - The results will change over time, but they are not likely to go away
- The results and conclusions presented paint an accurate picture of the potential for DE to shift costs to other non-participants and raise the overall level of rates, especially for residential and small business DE applications.

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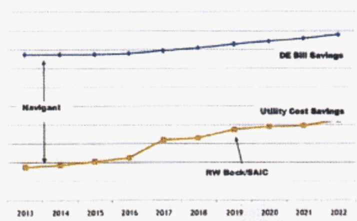
DE Cost Shifting "Billing Gap"
Illustrative $/kWh



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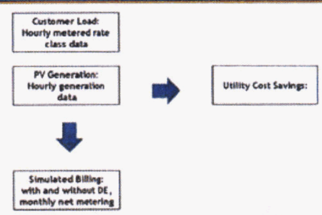
Evaluation Method - Overview



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Utility Cost Savings

- Projected 2013 costs
- Marginal impacts
- Generation capacity
- Fuel
- Line losses

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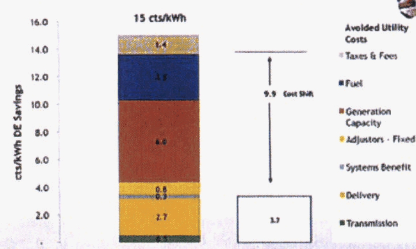
Results
Residential IB Rate



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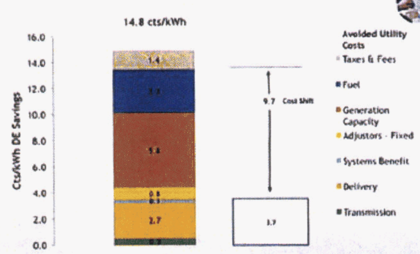
Results
Residential TOU-E Rate



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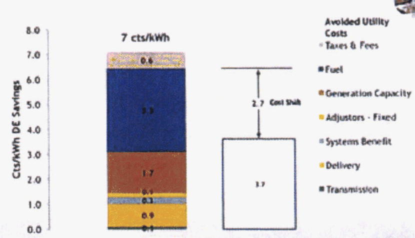
Results
Business-M Rate



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Summary of Findings

- Under current rate designs, DE shifts costs to non-participating customers and adversely impacts rates.
- The issue is primarily caused by rate designs that are not sustainable with a growing level of DE.
- The issue is exacerbated by net metering because it extends the cost shifting to more hours of the day or season, when solar is not generating.
- The cost shifting is higher for residential and small business customer DE applications because those rates rely more heavily on kWh charges for fixed cost recovery.

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Questions

- The December Navigant report indicated in the Executive Summary that the study was "not a societal cost-benefit analysis, but rather a billing gap study to assess the difference between the reductions in the bills of DE customers and the utility costs avoided by the solar generation and capacity of DE customers." Please explain the difference.
- In the current rate structures, please identify the proportion of fixed costs recovered through a kWh charge for each customer class in which net metered solar generation is deployed.

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Stakeholder Comment

APS left out some of the important benefits (utility cost savings is too low).

APS Initial Response

- Scope of study was to look at the potential for cost shifting with current rates and costs (including generation capacity, fuel and line losses).
- Other potential utility cost savings from DE will be the subject of the refresh of the SAIC cost study and discussions in these workshops.

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Stakeholder Comment

APS left out some of the important benefits (utility cost savings are too low).

APS Initial Response

- Scope of study was to look at the potential for cost shifting with current rates and costs (including generation capacity, fuel and line losses).
- Other potential utility cost savings from DE will be the subject of the refresh of the SAIC cost study and discussions in these workshops.

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Stakeholder Comment

Analysis was based on hypothetical customers, not real world data

APS Initial Response

- Study used representative customer examples, using real data
- Tested sensitivity of potential results to key assumptions
- Used hourly metered load research data and hourly metered solar generation
- Simulated hourly billing and net metering

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Stakeholder Comment

Study only looked at worst cases

APS Initial Response

- The evaluation phase focused on areas of concern: residential IB, TOU-E; Business-M - to test hours-use design structure;
- Residential TOU-D, Business-Large, Business-XL rates were not assessed because they were not areas of concern - the rate designs minimized the potential for cost shifting from DE.
- Business-S was not assessed because it has the same design and similar charges as Business-M.
- Business-XS not assessed - results and issues would be similar to residential IB

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Stakeholder Comment

Study's assumption of solar sized to 125% of peak load is unreasonable, should size system to 70% to 90% of annual energy

APS Initial Response

- Study used a solar system sized to 125% of peak kW, which was 74% of annual energy, for residential customers and 100% of peak kW, 42% of annual energy, for medium business customers

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Stakeholder Comment

Only looked at current utility cost savings - not the growth over time

APS Initial Response

- Scope of study was to look at the potential for cost shifting with current rates and costs
- Both rates and costs grow over time so the cost shifting will change, but it won't go away

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Stakeholder Comment

The cost shifting issues is not really a problem:

- Rates are not based on cost of service anyway
- Lots of rate subsidies between customers
- Small level of impact compared to total annual revenue

APS Initial Response

Cost of service is a primary driver for rates. Study focus was compatibility between certain rate designs and DE.

There are a few subsidies between rate classes. Most notably from small business class to residential class. But these are known, transparent, and vetted in rate cases. Also, in average class rate making - not everyone is average. Systematic and significant issues are addressed in rate making.

Impact may seem small relative to overall revenue, but it could very likely be a significant portion of a rate case or significant relative to annual RES budgets. Issue will grow with growth of DE adoption.

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Stakeholder Comment

Same issue for energy efficiency or just plain reduced consumption

APS Initial Response

APS does have similar concerns with energy efficiency that we address in rate cases. The issues are similar, but not the same for example:

- More customers have an opportunity to participate in EE than DE
- The cost shifting for an individual customer is typically lower for EE than DE
- Some EE measures can have a higher reduction in utility capacity costs than DE
- For many EE measures - if the measure temporarily fails, the load goes away. Not so with DE. This requires higher utility backup costs that are not charged to DE net metered customers.

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Participation Processes

✔	Opening Forum Creating a common set of expectations	February 21, 2013
	Workshops Detailed examination of the methodologies	
➡	Understanding Rates and DE Benefits	March 7, 2013
	Resource Planning and DE Costs	March 20, 2013
	SAIC Study and Other Models	April 11, 2013
	DE Business Cases	April 25, 2013
	Closing Forum	May 9, 2013
	Working Groups Ongoing dialogue and communications	

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Next Steps

- www.solarfuturearizona.com will be populated
- Material from today's presentation will be posted this evening
- Questions will be collated and matched to upcoming workshops

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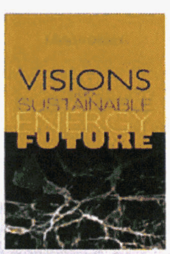
Questions?



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Meeting Notes

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Decision and Process Advisement in Energy and Water

TO: APS Workshop 1 Participants

FROM: Power Pundits LLC

RE: Workshop 1

DATE: March 27, 2013

As ordered by the Arizona Corporation Commission related to its 2013 Renewable Energy Standard Implementation Plan, Arizona Public Service Company began a multi-session Technical Conference with an opening forum February 21, 2013 at its Ocotillo site in Tempe. The second of six planned sessions was held March 7, 2013 at APS' Learning Center in downtown Phoenix. This Technical Conference is to evaluate the costs and benefits of distributed renewable energy and net metering. The sessions are designed to evaluate these costs for all customers—both those who have access to distributed energy and those who do not. The sessions are designed to explore such issues as environmental mandates, changes in generation requirements resulting from adding distributed energy to the generation stack, localized grid impacts, system losses and other relevant topics. APS engaged Mark Gabriel and his team at Power Pundits LLC to lead, moderate and manage this technical conference.

Seventy-three stakeholders registered for the opening forum. Of these, more than 60 attended in person. Up to 40 stakeholders participated via a conference phone connection.

Workshop 1: Understanding Rates and Distributed Energy Benefits was designed to bring together stakeholders holding a wide range of perspectives, experiences and levels of technical knowledge into a group setting to:

- gain an understanding of the work being done to update the 2009 Distributed Energy Solar System Costs and Benefits Study prepared by R. W. Beck
- gain a common understanding of the fundamentals of utility ratemaking
- get an overview of the components that make up APS' rates and how distributed energy impacts those rates

Copies of the agenda and presentation slides are available at www.solarfuturearizona.com. An audio recording of the workshop is also available on the site. These notes are the reflection of Power Pundits staff who participated in the workshop and are not a verbatim record. We believe they accurately reflect the sense of the day's meeting.

Workshop Opening

Mr. Gabriel opened the workshop by reviewing the goals of this process, its structure and ground rules and previewing the day's agenda. He noted that in this process, he would seek to develop a common understanding of the issues and options while working toward solutions and creating an understanding of the critical challenges facing all participants—both the stakeholders and the utility, and that the goal is to fulfill the Arizona Corporation Commission's Order. Mr. Gabriel reminded participants that Conference materials will be posted on the www.solarfuturearizona.com website and that questions, comments, suggestions and materials can be submitted by e-mail to techconf@aps.com.

He next reviewed the topics raised by stakeholders in the February 26, 2013 Opening Forum and outlined in which session(s) each would be tackled.

Alignment

Mr. Gabriel led a discussion on topics around which stakeholders could align, reminding all that alignment does not require agreement—only recognition of understanding and a commitment to support the decision once it is made. Upon consideration, workshop participants concluded they were aligned on these five topics:

- Transparency is critical
- Subsidies for all fuel sources should be considered
- Additional studies in addition to the Beck study should be considered
- Consumer education is important

  Participants said:
  - Policymakers also need to be informed
- There is a need for continued innovation and new approaches

  Participants said:
  - Innovation means research and development
  - Some stakeholders don't agree the current system is wrong/not working
  - Change to "continued consideration of new applications"

Participants determined they were not aligned on these two topics:

- There should be a level playing field among distributed energy technologies

  Participants said:
  - This is similar to the fairness issue
  - All technology should be on a level playing field, not only distributed energy
  - This process should only be considering distributed energy
- Current rate design may not be compatible with distributed energy

  Participants said:
  - Current rate design (net metering) may be compatible with distributed energy
  - Change "not compatible" to "cost recovery from"
  - Participants need to clarify how this is not compatible (Is it cost)?
  - Participants support adequate cost recovery
  - Current rate design didn't contemplate distributed energy effects
  - This is a square peg in round hole (it doesn't fit)

Participants determined these three topics needed further work for alignment to be reached:

- Rates need to provide fairness
  Participants said:
  - Fairness to whom?
  - Who pays?
  - Participants support utility cost recovery
  - Is it fair if participants have a willingness to pay?
  - Are rates fair now? Some stakeholders don't believe the E-32 rate is fair
  - This is a rate design issue
  - This issue doesn't necessarily apply to other utilities
  - The focus should be on supply costs (energy)
  - The RIM (rate impact measure) test does not equal fairness
- Solar represents an important economic development issue in AZ
  Participants said:
  - Change "issue" to industry; change to opportunity
  - Natural gas futures is an issue, not an opportunity
  - Support "industry"
  - The process needs a forward looking statement
  - Suggest participants work all these ideas in
  - Suggest participants delete all of these ideas
- A working definition on net metering

This definition was proposed:
Net metering includes the a) rate offset for distributed energy that serves a portion of the customer's overall consumption and b) bill credit and distributed energy generation that exceeds the customer's consumption and is carried forward as a credit against future bills.

Participants said:
  - Net metering does not include the rate offset; only the bill credit
  - The rate offset is available without net metering under PURPA
  - Some participants are OK with the proposed definition
  - Recommend using the Solar Energy Policy Association's definition:
    Net metering is a billing mechanism that credits solar system owners for the electricity exported onto the grid. Under the simplest implementation of net metering, a utility customer's billing meter runs backward as solar energy is generated and exported to the electricity grid and forward as electricity is consumed from the grid.
  - Net metering equals a bill credit; it is the export credit at the retail rate
  - The rate offset equals self supply
  - The rate offset is not a part of net metering; the offset also includes energy efficiency measures
  - Rate impacts/cost shifts apply to both components

Mr. Gabriel committed to bringing these three topics back to the stakeholders at the March 20 workshop.

SAIC Study

Joni Batson and Charles Janecek from SAIC reviewed the Distributed Energy Solar System or Cost Benefits from the 2009 R. W. Beck study. They reviewed the previously defined qualitative benefits from the 2009 study, described the data element being used in the 2013 study update being conducted by SAIC and outlined a number of the drivers that have changed in value since 2009.

Participants presented a number of comments and asked a variety of questions of the SAIC representatives. Questions for all following presentations are noted in bold and answers in italic.

Qs and As:

- **How many solar distributed energy systems monitoring hour by hour basis?**
  - *Large commercial scale systems are monitored; rooftop systems are now beginning to be monitored. Currently, 100-plus residential systems are being monitored on a 15-minute basis; Data provided to SAIC factors this in and will be fed into the model.*
- **Will stakeholders in this process get access to APS' solar energy data?**
  - *Yes.*
- **Has APS factored in the Flagstaff distributed energy experiment in the data provided to SAIC?**
  - *Yes.*
- **What percent of PV generation is subject to net metering?**
  - *Of PV installations, 98 percent are on a net metering tariff; Without looking into the data, APS can't confirm how much generation is exported under net metering.*
- **Participants agree that all information is helpful for the study. Can stakeholders get the data provided to SAIC? Can stakeholders get access now?**
  - *Data will be posted as soon as practical.*
- **Will there be transparency into the methodology used by SAIC? Transparency into the calculations?**
  - *Workshop 3 will include a segment where the model will be run so data inputs can be changed on the spot.*
- **How did SAIC calculate the energy costs?**
  - *SAIC used ProMod runs from APS.*
- **What will SAIC do to validate these data inputs?**
  - *SAIC is reviewing input assumptions: load, fuel, future avoided resources, etc. SAIC staff are not operating this model. SAIC staff do understand that inputs can influence results; however are comfortable that SAIC staff have a good understanding of APS' approach to production costs and believe the utility's approach is appropriate*
- **Who is completing the resource plan model runs, APS or is SAIC doing independent work?**
  - *SAIC is not performing the modeling. SAIC staff will ensure the results align with the firm's expectations based on the inputs. SAIC staff are not blindly accepting data; SAIC is reviewing the backup materials and detailed modeling output.*
- **Will you compare outputs to exogenous data, e.g., forward market data?**
  - *SAIC staff have not contemplated comparing model data with market forwards. SAIC staff have a good idea of what to expect based on the firm's own models and experience. SAIC staff are combing through data inputs and outputs before using in our model.*
- **Will any sensitivity analysis around key drivers (fuel prices, etc.) be conducted?**
  - *SAIC has a base case for fuel costs and will modify inputs for sensitivity.*
- **How long has SAIC been working on this study update?**
  - *About one month. [Note: APS later clarified that SAIC has not yet received all data needed for their analysis from APS.]*
- **We haven't yet received the data requested in the VoteSolar request.**

  - *APS committed to providing the date by which they will have answers to the initial VoteSolar data request. [*Note: APS provided all responses as of March 20.]
- **Is the Crossover model available?**
  - *SAIC is using a proprietary production state-of-the-art cost modeling tool. It is. It is an industry tool.*
- **Can inverters and controls be incorporated [into the study design]? What about considering Volt and VAR support?**
  - *Consider the cost effectiveness of utility scale, commercial systems and when and to what degree the value is set.*

Participant Comments and Observations

- Tucson Electric Power now has up to 12 MW of distributed solar energy that is monitored; TEP deals with real data and collects information for all our distributed energy systems.
- Some stakeholders have a concern about the forecast data being used. The economic situation is improving dramatically and would like to see this included in the model [Note: APS later clarified that this trend is included in APS load forecasts].
- What about academic data? The utility industry is in a dynamic industry. Scenarios are changing. Technology evolves. Eliminating changes is not setting accurate bookends. For example, consider variations in natural gas costs and add in single access tracking PV installations. Some stakeholders propose a wider range of options be included.
- A stakeholder raised the issue of fairness, stating SAIC has had access to the study data for four to six weeks. The stakeholder said the solar industry should be provided the same amount of time with the data. The stakeholder questioned that even if the data was provided today, [March 7] that is still less time than SAIC has had. How is this fair? The stakeholder requested APS please make the data available ASAP.[Note: As of 3/20, a portion of this data has been provided publically and an additional stakeholder workshop has been added to the technical conference schedule].
- A representative from TEP noted the outcome of this technical conference preference is specific to APS. They noted that TEP has metered data for their distributed resources; TEP knows it has increased O&M costs and impacts because of the lack of dispatchability; They noted that TEP cannot regulate with solar resources and cannot count solar as capacity—only the energy value. The stakeholder said Balancing Authority or WECC rules on reliability don't allow providing such capacity credit.
- Can APS consider the capacity value in a different way? Solar reduces load of customers and sets up for operating with other dispatchable resources. APS should provide this capacity value.
- Suggest APS evaluate the effect of on-peak heat rates to on-peak costs.

Open Items

- Why was solar water heating not included in the data elements for the 2013 update? This does not provide a complete picture. A major market component is missing. [Note: APS later clarified that SWH is not part of the cost of DE solar production which is the focus of the updated RW Beck Study. Solar penetration scenarios do include energy contributions of both PV generation and SWH energy offsets.]
- Based on the original study projections of low, medium and high distributed energy penetration, where is APS today compared to the 2009 forecasts?[Note: APS later clarified that current DE penetration in APS's service territory exceeds the amount that was forecast in the high scenario of the 2009 study.]

SEIA Data Considerations

Tom Beach, from Cross Border Energy, next provided additional explanation on the additional data considerations suggested by SEIA. He stated that market price mitigation is appropriate because behind the meter generation lowers demand, reduces natural gas demand and thus, lowers market prices. Mr. Beach said that southwest- or west-facing orientations of fixed solar arrays peak at 3 pm instead of need and better match the utility's peak. He noted that in a New York study, Perez and Hoff found grid security benefits and that the Austin [TX] tariff provides benefits because of the reduced outage risk cost. He supports a full hedge value because there is zero fuel cost for solar and this avoids natural gas price spike volatility. He recommended using forward market prices for this value.

Mr. Beach said that reductions in criteria air pollution results in environmental compliance savings and that because solar resources do not increase ancillary service and do decrease load, there should be a value to these reliability benefits. He noted that environmental savings, such as reduced water use, is important in Arizona. He said that distributed energy reduces APS' need to make wholesale purchases of additional renewable energy to satisfy its mandated Renewable Portfolio Standard requirements. He also noted that the RPS requirement is based on a percentage of load and since distributed energy reduces load, this also benefits the utility. He also answered a variety of questions and heard several comments.

Qs and As

- **Concerning time of day data, was this modeled vs. real data? Was this static vs. assumptions?**
  - *Production was based on time of day for variable generation. The production cost model is an hourly model. This was compared to an hourly load shape.*
- **Is it accurate that APS is not currently considering SEIA's data considerations? Stakeholders request these be included in the Beck/SAIC methodology?**
  - *Additional data elements are being considered by APS now and its staff are seeking to understand these and other qualitative considerations from other studies and how they work. The potential for these to be added to the SAIC analysis will be determined as part of future discussions.*
- **On the question of capacity, can you count PV if it's not dispatchable?**
  - *APS does count PV capacity as it reduces load on peak.*

Participant Comments and Observations

- Solar water heating is an integral part of the market. This is an economic development issue. Without this, APS is not getting the full picture.
- Stakeholders need to be clear about the Beck study. That study looked at solar distributed energy generally. In California, 40 percent of solar production is exported. Looking at the whole picture is a different question: self serve vs. exports.
- This study should be addressing distributed energy's entire impact. Hot water is part of mix. It should be kept in the study. If this process is only looking at net metering, then it needs to shift.
- Capacity benefit should be considered. The Beck study only gave credit for avoiding building the next generation or transmission facility. Other studies have taken different views. What's installed now—250 MW—will push off new capacity builds. This value should be captured and included now, perhaps at net present value? The study is looking at snapshots in 2015 and 2025. How many facilities are avoided by those dates? No avoided capacity until 2025; then this is factored into the 2025 view.

Additional Studies

On the topic of additional studies to be considered, participants provided several thoughts, including:

- SEIA will send a list of studies. See Vermont Study literature review list.
- Define inputs; make inputs transparent for replication in other studies
- Consider the Cross Border study on net metering in California. There are 10,000 systems, residential and commercial/industrial. Net metering is cost effective in California. A participant will provide a link to the study posted on the Vote Solar site.
- See the 11 studies on the Vote Solar site. A stakeholder will provide information.
- Suggest folks provide a description of the studies and their conclusions, not just a list of studies. List the benefits that were evaluated in each study.
- Please summarize studies in a format that would be valuable to this conference. The literature review in the Vermont study has descriptions of these studies.
- How will this process move forward? Participants have heard from SAIC. Can APS and the facilitators find time over the next two workshops to discuss additional models? This process should discuss and consider key elements in them, how to introduce potential content into this forum, what variables can be added to SAIC's work, what should be added on top and what should be changed in SAIC's approach. [Note: A conference call was held on March 14 to discuss these issues.]

Qs and As

- **The study output is using 2015 and 2025 snapshots. The SAIC study is missing the 2020 data point. Stakeholders suggest adding this data point.**
  - *APS will see if this can be accommodated. [Note: The 2020 data point will be added to the SAIC study.]*
- **Is there an opportunity to provide more time to do more work? This can't happen in a few weeks. Would APS consider requesting an extension from the ACC?**
  - *APS is working to maintain fluidity in this process compared to "being done." This process will have a real-time exploration of the SAIC model on April 11. Participants will see what happens when inputs are changed. That's not a "done" date. Additional variables may provide additional insight. [Note: APS committed to extend the technical conference an additional session, concluding by late May.]*

Participant Comments and Observations

- The 2009 projection was for 100,000 MWh of solar distributed generation by now. APS is now at 400,000 MWh. If net metering is still to be in place, suggest the study go to twice as much at a medium penetration and twice again for a high penetration.
- APS noted that the data set for SAIC is close to completion, they haven't had it for a month. APS will post the data to the project website when it is available.
- Please include the metadata along with data so stakeholders understand how it was collected and what it means.

Open Items

- Can APS work with a subgroup on other variables and what can be included within the utility's rate structure and net metering construct?

Utility Rate Making

Tony Georgis, NewGen Strategies and Solutions, presented a session on the fundamentals of utility ratemaking. He reviewed the rate-making process, including policy objectives and strategy, determining revenue requirements and cost of service and touched on rate design elements. Georgis outlined the five steps in rate-making and walked participants through these steps using fictional examples:

- Determine the revenue requirement
- Functionalize the costs and services (production, transmission, distribution, etc.)
- Classify costs (demand, energy, customer costs, etc.)
- Allocate costs among customer classes
- Design rates

He also reviewed both intra-class and inter-class subsidization and provided an example of each. Finally, he discussed the difficulty in aligning rates and rate structures with costs to serve. Mr. Georgis also answered numerous questions and received a variety of comments.

Qs and As

In looking at Slide 30, APS Residential Cost Structure vs. Revenue Collections, why is this is a solar only problem?

- o *This is a rate design problem. APS is shifting this mix slowly. Policy plays a role; PV is exacerbating this problem.*

- **APS is focusing on residential customers in Slide 30. The commercial mix is different. Several hundred thousand customers are mixed together.**
  - o *Low load factor customers are paying more; high load factor customers are paying less. No one is paying perfectly matched to costs.*
- **On typical depreciation for a powerplant, is the asset then removed from the rate base?**
  - o *Yes, but reinvestments are added back in, so the asset base doesn't usually decrease.*
- **Are known and measurable adjustments, current costs not just the test year?**
  - o *They are the modified test year. This could be two years lagging. Some adjustments are included but this is not forward looking as in California.*
- **Aren't rates designed to recover current costs?**
  - o *No, historical costs are used, not current costs.*
- **Over time, won't rates stay reasonably in balance?**
  - o *This is not always true, adjustments are specific. Revenues, customer growth and sales always need to be adjusted after the fact.*
- **What are the benefits of a historical year compared to a forward test year?**
  - o *A forward test year may result in better synchronization between costs and revenues. However, this is not allowed in Arizona. There are some advantages to a forward look.*
- **On Slide 42—Revenue requirement, there is an example of a return on a rate base. If the rate base decreases as assets are depreciated, does the revenue requirement also drop?**
  - o *Yes, but this doesn't happen in reality because of reinvestments.*
- **In Slide 47 showing APS' Functionalized Revenue Requirement, is the data from the 2010 test year?**
  - o *Yes.*
- **Is the asset base a fixed cost?**
  - o *Yes.*
- **What are regulatory assets?**
  - o *Regulatory assets are a special accounting class where a high-cost expense that would normally be classified as O&M is classified as a capital cost so that it can be recovered over the life of the asset. One example is relining a penstock at a hydropower facility. This is an O&M activity but its purpose is to significantly extend the facility life. It is so expensive that if it were expensed in one year, it would result in rate shock and thus is treated as this special class of asset called a regulatory asset.*

- **These are blended rates. Stakeholders are concerned about marginal rates for solar; the off the top costs.**
    - *The process needs to consider the embedded as well as marginal costs.*
- **How do you treat system losses? The percentage is 15?**
    - *This is accounted for in the allocation factor at the point the user takes power off the system. Generation is always more than what is purchased. There are two kinds of losses, load and magnetized. Mr. Georgis commented that fifteen percent seems high.*
- **Did the Beck study account for losses on the capacity side as well as the energy side?**
    - *Yes*
- **Isn't there another class of customers—self generators—that reduce coincident peak?**
    - *Utilities can calculate the worth of self-generation and how that adds value to the utility. Utilities can price it properly and send the correct signal (stick or a carrot).*
- **Is this a separate customer class or a Demand Side Measure?**
    - *This is not a separate class (see slide 53) based on how energy is used.*
- **On slide 58, what does AED mean?**
    - *Average and excess*
- **What cost allocation method does APS use?**
    - *APS' methodology is provided in each rate case.*
- **On slide 65, if all residential customers were at a 10-percent load factor, demand charge would not be $16.67, it would be higher?**
    - *Yes*
- **Considering the load factor shown on the cost curve on Slide 66, isn't it important when the peak demand occurs? Filling valleys reduces costs. This can shift the peak to a time when capacity is cheap and available.**
    - *This doesn't reduce the cost of the assets needed to serve that house. The system is still built to sustain the non-coincident peak use.*
- **In the short run, yes, but in the long run, the utility will design the system on customer characteristics. Participants should have more conversation on this topic.**
    - *PV is peaking in the afternoon. The system peak is at 7 pm. The utility still has to build assets to serve that peak.*
- **Has Mr. Georgis done rate design to encourage energy efficiency and maximize the use of solar resources? Does daylight savings time change the mix?**
    - *Inclining Block rates incentivizes conservation. Feed-in tariffs incentivize PV. One example: SCE and SDG&E-commercial rates. Reduced demand charges and increased energy charge (similar to a demand rebate or critical peak pricing).*

Participant Comments and Observations

- What are the definitions on fixed and variable costs? It is implicit in some time scale. In the long run, the utility will change and replace its system. It's an important economic truth. There are very few costs that are fixed in the long run. The time dimension says this is a long time resource.
- An investor-owned utility invest its money in assets vs. buying from a third party. Is this a conflict of interest? If the utility didn't own any assets would this change the utility's fixed vs. variable costs?

Open Items

- Do solar generators get credit for distributed energy on the residential side where there are thus fewer losses? Do they get credit for this?
- What about less transmission impact because solar generators have fewer losses from distributed energy on the system? Do they get credit for this?
- If a PV customer is exporting in most of peak times, how much export credit do they get benefit for?

- Are there specific rates for PV customers? How many APS classes and sub factors? Are we moving to more diversification to accommodate differing load factors?
- In terms of subsidization, what about universal service requirements; rural vs. urban consumers have different costs, yet their rates are the same?

APS Rates Overview

Chuck Miessner, APS Pricing Manager, provided an overview of APS Rates and the Impact of Distributed Energy Solar Resources. He explained APS' major rate classes, discussed the billing elements and charge types, outlined specific rate designs and distributed energy bill savings and presented a conceptual overview of cost-shifting and the resulting billing gap issue. He also briefly outlined the purpose, methods and results of the Navigant study and provided initial thoughts on APS' responses to a number of comments and critiques.

Mr. Meisner also answered numerous questions and received a variety of comments.

Qs and As

- **What factors have driven residential TOU rate adoption?**
  - *The rates have been in place a long time, since the early '80s. APS has done marketing and the inclining block drives some large users onto TOU rates.*
- **For the billing elements shown on Slide 95, is the fuel charge zero-based or is some portion covered in fuel charge?**
  - *The adjustment is the delta between what's included.*
- **In Slide 97, is on-peak the same winter and summer?**
  - *Yes*
- **Please explain cost types shown in Slide 98.**
  - *Cost drivers are key. Cost is based on cost of assets in the ground; not on future avoided costs (though allocated based on average and excess).*
- **Please explain the environmental adjustment surcharge?**
  - *This is for pollution control equipment; it's a new surcharge.*
- **Does APS get RES credit from rooftop solar? Why isn't that a utility cost savings?**
  - *Mr. Meissner said he had a couple of thoughts on this and on hedge values and that he would elaborate later.*
- **The business rate shown on Slide 103 went through a significant change; please discuss?**
  - *It was redesigned to look more like large customers with more customers under 27% Load Factor. APS eliminated energy tiers. Solar didn't improve medium load factor customers, only provided savings to second tier consumption, not first tier. Grade schools are at 30-35 percent LF. Solar installations reduced them to the lower tier. Moving them to TOU rates resolved most of the problem.*
- **If benefits exceed costs, the utility should be able to figure out a way to spread out benefits.**
  - *Agree; the utility must first determine if this is worth doing (cost-benefit).*
- **Did we skip over cost-benefit test for distributed energy?**
  - *The discussion focused on the Cost-Equity test in the Navigant study.*
- **Before this process get to this, participants need to agree on cost-benefit ratio, as a common starting point. Suggest the process back up.**
  - *Integrated Resource Planning is the overarching cost-benefit piece and the focus of the next workshop.*
- **The cost equity test ignores benefits that accrue in future years.**
  - *The cost equity test could do so; the Navigant study didn't lay that out. It looked at today's situation.*

- **On Slide 110, why not present the other side? Utility savings wipe out all other costs; results in free rates (extreme view). What happens if cost savings are greater than bill savings?**
    - *The utility would want to encourage this. The key is to have no adverse impacts on your neighbor.*
- **Does the consumer get the TOU $ credit?**
    - *Yes, on and off peak, based on time and season.*
- **Can't the utility look at cost shifts within classes over time? APS incurs costs today to save tomorrow; Suggest present value analysis.**
    - *APS doesn't think these issues will go away over time.*
- **Is a 50 percent demand stability built in? Does APS recover transmission and distribution costs thru kWh?**
    - *50 percent is recovered through kW charges; customers' demand is reduced by 50 percent; this is how it got negotiated in rate case settlement.*
- **Is this not intending to use 50 percent costs?**
    - *No, APS uses metered costs.*
- **Lost Fixed Cost Recovery—is this stranded capital costs? Write off?**
    - *Yes, stranded costs that will be recovered in the future.*
- **What is LFCR?**
    - *It is not revenue decoupling, but a certain amount per decrease in demand from distributed energy.*
- **What other cost shifts are you talking about on Slide 115? Other examples?**
    - *Mr. Meissner noted he would discuss this in the comments and critiques section.*
- **As capacity benefits increase, costs do go up?**
    - *Yes, APS recognizes this and participants need to discuss. Cost shifting won't go away.*
- **The Beck study shows the billing gap at 7 cents and the energy savings 8 cents. Should the lines should be closer together?**
    - *Gas prices are a factor. Gas is now at 3 cents. Currently, APS has a 15-cent billing gap based on the Inclining Block and time-of-use rate plans.*
- **Is the sky falling or is this just an emerging issue?**
    - *The sky is not falling. APS is seeing rapid growth in distributed energy. This is not a huge cost shift today. Participants need to discuss and recognize that this is not sustainable from APS' perspective.*
- **Are avoided costs based on the EPR-6 rate? Are these different avoided costs than used today?**
    - *Mr. Meissner noted he should have said EPR 2/6; EPR 6 is being updated.*
- **What about the costs for regulation and ramping to support distributed energy?**
    - *APS didn't include program costs for the distributed energy program. APS only looked at the technology itself. APS didn't include any ancillary service; this is a pretty small cost—a couple of mills, with a savings of one-tenthof a mill. APS only considered production costs for fuel and line losses.*
- **How did APS pick the size of the Inclining Block customer?**
    - *APS looked at the distribution of usage of all Inclining Block customers and a sample of distributed energy customers. APS used 1,260 kWh/month. [Note: APS actually used 1,650 kWh/month for a residential customer.]APS took a heuristic approach; looking at 2010 before the PV installation compared to 2011 after the installation. This could range from 15.5 cents down to 13 cents.*
- **Is this average cost or on the margin? How did you collect all of your costs?**
    - *Average.*
- **The 3.3 cents of fuel costs, are the average fuel costs included in rates?**
    - *Yes, 6 cents is generating capacity costs. Some of the generating capacity and some of the delivery costs are in the TOU demand charge.*
- **The fuel adjustor covers volatility; now APS has shifted this risk to customers. Why?**

- *This is a better solution than an annual rate case.*
- **Solar is a 20-year hedge against gas prices. Utilities can only value solar against a 20-year gas price hedge. Doesn't APS have a long-term strategy to hedge against gas price increases?**
  - *The goal may not be to get to zero. The goal may be to get to a smaller percentage of hedge. Buying a fixed asset is taking a position but the utility also may be stuck with it.*
- **Slide 132 discusses subsidies between rate classes. Are there other policies that lead to cost shifts?**
  - *Small business to residential cost shifts; low income rate discounts; in the Inclining Block rate, tiers for conservation purposes; Basic Service Charge for the E-12 rate.*
- **The reductions in sales discussion and the use per customer, is this growing or declining?**
  - *This has been declining for several years due to the recession but conditions are forecast to improve in the coming years.*
- **Are additional sales are offsetting these costs?**
  - *Costs are associated with increasing use.*

Participant Comments and Observations

- Is the 1.4 cents for taxes and fees is a pass thru? Shouldn't the 15 cents/kWh be 13.6 cents?
- On Slide 123, residential customer savings is 15 cents; business customer savings is 7 cents? Do commercial customers need a PBI to make up the delta?
- With 14,000 distributed energy customers, reliability is high; other utility savings are the subject of the Beck study refresh—capacity benefit; agree with the system diversity of distributed energy.

Workshop Wrap Up

Mr. Gabriel closed the workshop by reminding participants of the next workshop and that most data should be provided to stakeholders by March 20. He noted that APS will hold a call with interested stakeholders, Thursday, March 14 at 10 a.m. to discuss the SEIA recommendations regarding costs and benefits. Proposals for the alignment topics needing work will be brought back to the March 20 workshop for consideration. He encouraged stakeholders to send questions and comments, to watch the Website for new data and to register for future workshops. He also received several questions.

Qs and As

- **There are several outstanding VoteSolar questions. Only 10 out of 37 have been addressed. What is the time frame for completing this?**
  - *This will be completed within next week. They will be posted as they are finished.*
- **What is the overall timeframe for this process? Is the last meeting set in stone?**
  - *APS is flexible in looking at the time frame and will address any adjustments during the March 20 meeting.*

Stakeholder Call, March 14, 2013

Meeting Notes

POWER PUNDITS LLC.

Decision and Process Advisement in Energy and Water

TO: APS Technical Conference Participants

FROM: Power Pundits LLC

RE: March 14, 2013 Stakeholder Call

DATE: April 11, 2013

Mark Gabriel, Power Pundits LLC, led a call March 14, 2012 among stakeholder and APS staff as an adjunct to a multi-session technical conference on distributed energy and net metering.
The following agenda items were discussed:

- Report on status of responses data request to APS
- Review and discussion of SEIA's additional data considerations
- Future Technical Conference schedule

An audio recording of the conference call is also available on the www.solarfuturearizona.com website. These notes are the reflection of Power Pundits staff who participated in the workshop and are not a verbatim record. We believe they accurately reflect the sense of the call.

APS data requests
Mr. Gabriel reported that four responses are now posted on the solarfuturearizona.com website answering most of Vote Solar's current questions. APS expects to make the last data set available later March 14. APS has also provided five data sets that are being used by SAIC in its analytical work. APS is working to make all of these elements available by March 20. A call participant requested APS provide the data in Excel format.

Mark reminded participants to send questions to techconf@aps.com. He noted that numerous documents are now posted in the Data Room of the website and reminded participants they could contact him or LaVerne Kyriss if they can't find something on the SolarFutureArizona.com website.

SEIA data considerations
Tom Beach, Crossborder Energy, reviewed the data considerations submitted by the Solar Energy Industry Association. He pointed participants to several items posted on the SolarFutureArizona.com site including a summary he prepared outlining data sources for additional benefits of renewable distributed generation, the literature review for the Vermont net metering study, and summary of the California avoided cost model. He noted that his summary also provides links for additional information.

Market price mitigation

Mr. Beach stated that market price mitigation in both electric and natural gas markets should be factored into study benefits. He cited both the Perez/Hoff studies in NY and NJ as references for this approach.

Qs and As

- **Is there a limit on the penetration factor? Is this based on how much natural gas is on the margin? How do these play together to get through the deep natural gas resource stack?**

This could be different in different markets and depending on the specifics of the resources, the age of the plants, their heat rates, etc.

- **How do you estimate this benefit from an analytical perspective? Do you use a price elasticity curve? How can you move the market, particularly in a large interconnected market?**

This is definitely price elasticity; it can result in the same effect as lowering demand.

- **Is this worth studying because we don't know the answers? How do you estimate this analytically?**

Lower demand equates to lower prices. Resource plan scenarios with different amounts and kinds of resources can be evaluated with production cost runs showing market price differences among the scenarios.

- **What percentage impact does distributed generation have on the market compared to other resources?**

The Lawrence Berkeley Lab study shows a small impact over a large market n the neighborhood of $5/MWh of renewable generation. This is a small benefit, but it is magnified because it affects the volume in a large market.

- **These calculations were done for locational market price markets; how do we calculate this for bilateral markets?**

While Arizona does not have the granularity of LMP markets, you still have a market.

- **What does it take to move a market? With the California LMP market can see the price shifts. Palo Verde is a liquid market with a large volume of bilateral trades. APS is not sure it knows how to price this impact. In LMP markets, all trades are at the LMP price. In a bilateral market, only a few trades are at the LMP price.**

Perhaps this isn't the setting to get into these details. The Arizona market is not as granular as the California market. However, there is enough transparency that people are transacting at close to marginal price.

Participant Comments and Observations

- **Recommend APS take into account the value of commercial solar, not just distributed energy.**

Value of southwest- or west-facing orientation

Mr. Beach noted that there is increased capacity value from southwest or west facing orientation of arrays because of later peaking. He noted that the Beck study did consider this somewhat and noted that profiles for various orientations are available.

Grid security benefits

Mr. Beach stated that distributed energy reduces loss of load probability and provides benefits from reduced outages. He said this can be calculated on the value of reducing outages, referring to Perez and Hoff's work in NY and NJ. He said this was considered in the Austin [TX] solar tariff but not included.

Qs and As

- **APS has difficulty understanding the actual benefit, how to ascribe it and determining who pays for this. Can you provide more explanation?**

This is a bigger scale than individual neighbors getting some benefit. DE provides a system that is more resilient in avoiding outages such as the Northeast blackout.

- **Doesn't a utility adjust reserve requirements to account for this DE? What about the need to increase reserves to accommodate DE? Doesn't the LOLP adjust itself?**

A utility can reduce reserves by relying on DE. Reserves are a real cost or real savings. A utility that relies on DE saves money. If APS tries to accommodate this savings in its capacity valuation, it may be adequate. This savings should be included in the overall benefit of renewables.

Value of fuel hedging

Mr. Beach stated that solar has no fuel cost, thus avoiding fuel cost volatility. He said natural gas forward prices are used to determine future costs. In an approach to eliminating volatility, CA used natural gas prices to determine the savings to be attributed to distributed energy, demand response and energy efficiency. Mr. Beach said using fundamentals forecasting accommodates a longer time scale than that provided by the futures market. He referred to the E3 data and model. He noted that the California PUC uses Henry Hub natural gas prices, adjusts for transmission costs to California and adds a transaction cost. He said Austin [TX] uses a similar approach.

Qs and As

- **Compared to other commodities and fuels, the forward pricing curve is higher the further out in time. How can a utility differentiate between a coal contract with future price escalators and indices linked to natural gas/oil prices? APS doesn't monetize these values for rate making puposes because we use historical costs. A nuclear contract would also dampen natural gas escalation. How is this different?**

Solar has no fuel cost and thus no volatility. There is a small amt of O&M. A utility can value this lack of volatility by comparing solar's cost to the alternative costs. If the utility builds a gas plant and contracts for a long-term gas supply, this would provide a comparison. This is the reason for using the forecast market for gas prices.

- **How does the utility distinguish between hedging and the forward curve? It seems like you are proposing a feed-in tariff rate. APS doesn't set rates on future costs—only historical costs. This sounds like effectively monetizing the entire forward curve to provide a value proposition from solar.**

Yes, utility economists have differing opinions on forward vs. fundamental prices. This is the subject of a Lawrence Berkeley Lab analysis of Energy Information Agency gas price projections. Forward prices seem to be consistently higher than fundamental prices. An additional premium in forward prices is a reflection of being able to fix the price today for long-term future purchases and eliminate volatility.

- **Considering distributed energy: it seems that a participant is hedging his or her own natural gas futures price. What about other consumers? To whom does this value go?**

That's why the utility is trying to estimate value of this resource by trying to price out a comparable resource to a renewable resource that comes with a price fixed for next 20 yrs.

Environmental compliance savings

Mr. Beach described environmental compliance savings as those related to criteria air pollutants or reductions in water use.

Qs and As

- **What's the difference between [environmental] compliance [savings] and water savings?**

There's no difference.

- **Concerning the avoided capacity analysis, is this a case of broad buckets? Are the environmental costs (in item 7) similar to these? Are we really avoiding the cost of a new natural gas unit? New units have state-of-the-art emission controls built into the capacity costs. Does reducing emissions get us part of the way there?**

Yes. In California, a CCT is used as the marginal resource. This includes state-of-the-art emissions that are included in the plant capital costs. In California, utilities are required to purchase offsets for emissions. These are also included in the capacity costs for that plant. This is one way to handle this.

- **Are these emissions external to environmental controls?**

With a gas plant, a utility cannot get emissions down to zero.

- **Do different regions require different costs for environmental compliance? For example, the offset purchases required in California aren't required in Arizona.**

Yes.

- **Concerning the valuation of water: At Palo Verde, APS has a water contract embedded in costs for that resource. If generation is backed off, costs are avoided. This is already included.**

When a utility backs off generation from a plant requiring cooling water, this water can be used for other purposes and has a value on the market.

- **APS rates reflect avoided costs. APS is still trying to reconcile life cycle vs. long term costs.**

These costs are not in rates today but will be included over 20 years and thus should be factored in.

- **Concerning rate making impacts today compared to future rate cases is difficult. APS is required to look at today's rates, not future costs. It is difficult [under our state rules] for APS to pay for something today when we won't see the value until 2020.**

The utility should be trying to value a resource that will be around for 25 years. The utility should prepare a long-term forecast using lifecycle costs for all plants. Whether a utility uses a historical or forward basis for rate-making doesn't matter.

- **What about the water value? Is the treatment similar to hedging for natural gas using long-term contracts?**

Yes, if this value is available. Long-term water costs are embedded in contracts.

- **Is this escalated?**

APS owns a lot of the land for the wells and the water rights; the costs may not be subject to escalators.

Reliability costs

Mr. Beach explained that reliability costs are primarily avoiding Ancillary Service costs. He referred to the E3 study. He noted that in California, ancillary service requirements are based on load. Because solar distributed generation reduces load, ancillary service costs are reduced. He added that this was a relatively small benefit adding that it is based on a Western Electricity Coordinating Council requirement that should also apply in Arizona.

Environmental savings

This was addressed in environmental compliance savings.

Avoided RPS wholesale purchases

Mr. Beach described avoided RPS wholesale purchases as a "catch all" category, noting that it's often difficult to quantify all the benefits of renewable resources. He said that many states have RPS requirements and some have set asides for distributed generation. DG can count against a utility's RPS requirement. These resources also reduce utility sales. Since RPS purchase requirements are based on utility sales, DG reduces this requirement. The benefit can be calculated on the premium paid for renewable compared to what a utility pays for "brown" resources. If renewables cost the

same as "brown" power, the benefit is zero. If all benefits are priced out in the other categories, a utility may not need to price in this category. If a utility is paying a premium for RPS resources, it could be calculated. The California PUC has a calculation that factors the marginal cost of RPS resources compared to a natural gas plant. The
California model for avoided costs can be downloaded in an Excel format so assumptions can be changed.

Future technical conference schedule
Mr. Gabriel noted that Technical Conference participants had requested an additional session, which would extend the schedule. Two participants noted that this would be helpful. One requested that stakeholder have the same amount of time with data that SAIC has had, stating that is would provide reasonable access to the data. One stakeholder noted that IREC had contacted a firm about preparing a study but their staff is not available until the summer and the results wouldn't be available until August.

Qs and As

- **What's APS' timeline after the technical conference is completed?**

APS expects that by end of this conference, the utility will have a better idea of when it will have its solution back to the stakeholders for review. APS cannot confirm the exact timing, but it is expected this summer.

- **What's the end game for this effort? Is the goal to impact the 2014 plan? If so, what are the relevant dates?**

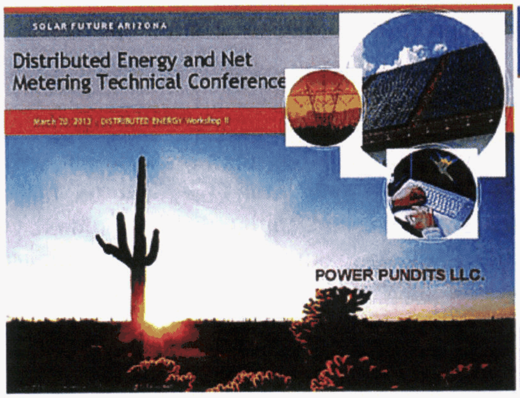
ACC staff noted it is looking at a solution to implement in APS' 2014 plan. If the draft plan is filed this summer, one could reasonably expect a decision by year-end. ACC staff would appreciate additional information in the six-month window in which they will be reviewing the proposal. ACC representatives believe it's completely appropriate for parties to disagree even at the end to a process. The Commission understands this and expects to have competing facts and figures. Other parties can file additional information for consideration in APS' 2014 plan.

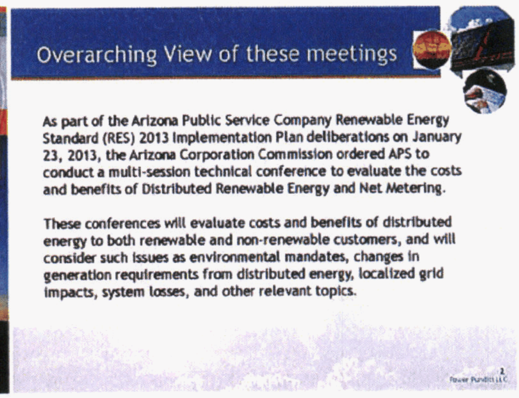
Comments and Observations

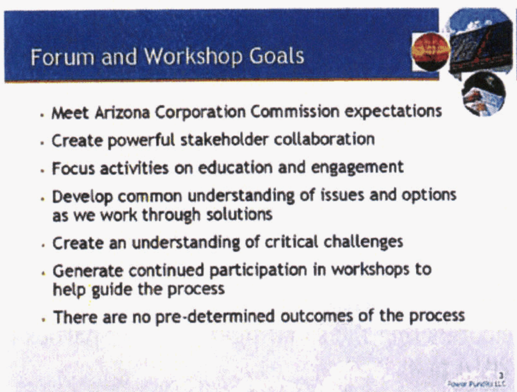
- Stakeholders could introduce additional details to the ACC in response to APS' filing.
- Solar water heating needs to be a part of the solution.

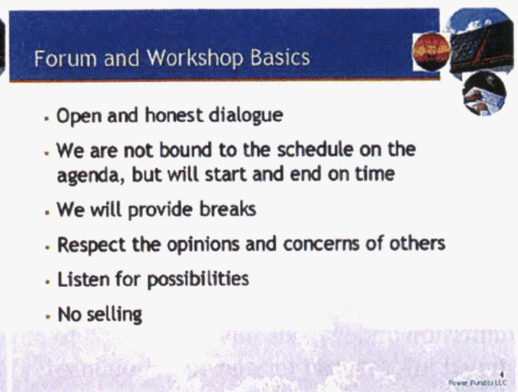
Workshop II (March 20, 2013)

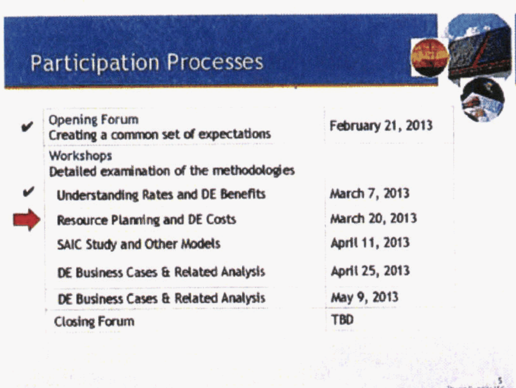
Presentations

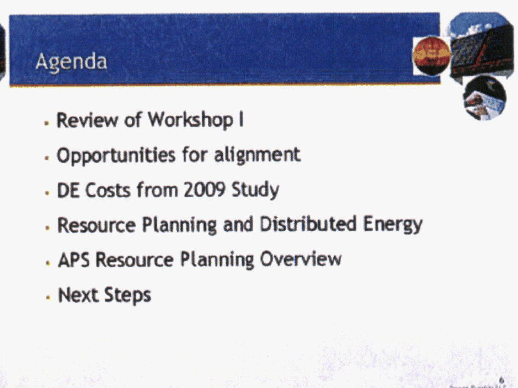












Agenda

8:30	Welcome and Introductions	*Mark Gabriel*
9:00	Discussion of revised alignments	
9:30	Cross-Border Benefits Study	*Tom Beach*
10:30	Break	
10:45	Fundamentals of Resource Planning and Distributed Energy	*Bob Davis*
11:45	Lunch	
1:00	Resource Planning and Distributed Energy Continued	*Bob Davis*
2:30	APS Resource Planning and Distributed Energy	*Paul Smith*
3:30	Break	
3:45	Distributed Energy Costs and Benefit Discussion	*Open Discussion*
4:45	Critical Issues, Deadlines and Concerns	*Mark Gabriel*

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Review of Workshop I

- DE rate impacts can occur through behind the meter rate offsets (self supply) as well as net metering bill credits
- APS service is highly driven by fixed costs
- APS rates are based on historical test years
- DE impacts both costs to serve and revenues collected
- For residential and small commercial rate categories, there is a mismatch between cost type and charge type (causation vs. recovery)
- DE customers have a unique load profile, benefits and costs

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Seeking alignment

Alignment:

The proper positioning or state of adjustment of parts in relation to each other

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Alignment Model

- Points of view are voiced (reasons for, reasons against, up-sides, down-sides)
- People listen for understanding
- Points of view are considered
- You do not have to *agree* to align; merely recognize you understand and will support
- The team will:
  - **Restate and affirm when alignment is reached**
  - **Make the decision with action steps**
- Once made, all support 100%.

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Alignments

- Rates need to consider impacts to DE participants and non-participants, while supporting utility cost recovery.
- Solar energy provides economic development opportunities in AZ.
- Net metering is a billing mechanism that credits solar system owners for the electricity exported onto the grid. Under the simplest implementation of net metering, a utility customer's billing meter runs backward as solar energy is generated and exported to the electricity grid and forward as electricity is consumed from the grid.

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Opportunities For Alignment

- DE rate impacts can occur through behind the meter rate offsets (self supply) as well as net metering bill credits
- APS service is highly driven by fixed costs
- APS rates are based on historical test years
- DE impacts both costs to serve and revenues collected
- For residential and small commercial rate categories, there is a mismatch between cost type and charge type (causation vs. recovery)
- DE customers have a unique load profile, benefits and costs

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Evaluating the Benefits and Costs of Net Energy Metering in California

Tom Beach

Crossborder Energy

March 20, 2013

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Overview

- General observations on net energy metering (NEM)
- The scope of a cost / benefit analysis of NEM
- The need for a new C/B analysis of NEM in California
- Crossborder's new C/B analysis of NEM features:
  - Both residential and C&I markets for the CA investor-owned utilities (IOUs)
  - 2012 rates and updated rate escalation
  - Updated E3 avoided cost model used for CPUC demand-side programs
  - Customer usage and system size data for more than 10,000 NEM customers in all three IOU territories
  - Analysis conducted by rate schedule

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Net metering is a billing arrangement

- Net metering is simple and easy for prospective customers to understand.
  - "Running the meter backwards" is the essence of NEM.
  - The impacts of NEM on non-participating ratepayers are complex.
- Without NEM, customers have rights under federal law (PURPA)
  - To interconnect with the grid
  - To offset their own load
  - To receive an avoided cost price for exports to the grid
- The essence of NEM is the price received for exports to the grid. Does the retail rate credit accurately capture the value of the power exported?
- Most of the output of net-metered PV systems never touches the grid.
  - Typically, 55% to 75% of PV output serves the on-site load, before power is exported to the grid.

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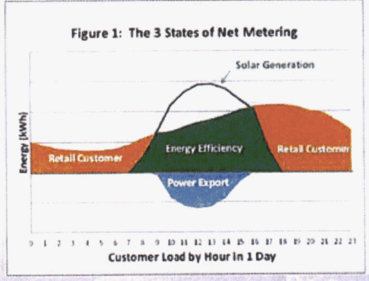

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Cost-Benefit Analyses of NEM or DG in the Context of Utility Cost-effectiveness Studies

- Cost-benefit evaluations of demand-side resources are common.
  - NEM or DG should be evaluated using the same approach as EE and DR resources.
- Cost-effectiveness of NEM is not the same as the cost-effectiveness of a DG resource.
  - Be clear on whether NEM or DG is being evaluated.
- NEM cost-benefit analyses are ratepayer impact (RIM) tests.
  - Only examines the ratepayer impacts of the NEM billing arrangement.
  - The utility's lost revenues are the principal cost.
  - Not a total resource cost (TRC) or "societal" test of the cost-effectiveness of DG technologies.
  - In TRC tests, the capital and operating costs of the DG resource are the principal costs.
- States place different emphases on RIM vs. TRC tests.
  - For example, California does not use ratepayer impact tests to evaluate energy efficiency or DG programs. See D. 09-08-026, at 24-26.

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Major Costs (+) and Benefits (–) in Demand-side Cost-Effectiveness Analyses

Category	Total Resource Cost (TRC)	Ratepayer Impact (RIM)	Participant (PCT)
Capital and O&M Costs of the DG Resource	+		+
Utility Lost Revenues or Customer Bill Savings		+	–
Avoided Costs -- Energy -- Capacity -- T&D, including losses -- Ancillary Services -- Environmental -- RPS	–	–	
Federal Tax Benefits	–		–

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Scoping a Cost/Benefit Analysis of NEM

- Focus on the power exported to the grid.
  - Typically, this power immediately serves nearby loads...
  - ... and displaces power the utility would have delivered from remote sources.
- Focus on DG as a long-term resource.
- Costs:
  - Utility loses revenues, from running the meter backward.
  - Incremental billing and administrative costs
  - Integration costs
- Benefits:
  - Costs that the utility avoids as a result of NEM exports to the grid:
    - Avoided generation costs, including environmental and RPS costs.
    - Avoided delivery (T&D) costs, including avoided line losses and avoided T&D investment costs.

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A Common Misconception

- Assertion: NEM credits at the full retail rate mean that the NEM customer does not pay for certain utility services from which it benefits.
  - T&D infrastructure costs (i.e. "the grid")
  - Public purpose program costs
- Response:
  - NEM exports are more valuable than the generation component of the retail rate, i.e. than the utility's average cost of generation.
  - Generators do not pay to have their power delivered. NEM customers who export power should be treated comparably. The retail customer who uses NEM exports (a neighbor) will pay those T&D costs.

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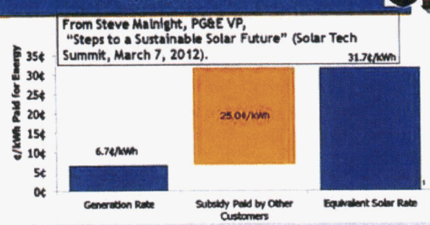
Solar Subsidy



Residential solar customers effectively sell their generation to the utility at 31.7¢/kWh; while the generation part of the rate is 6.7¢/kWh. The difference is a subsidy funded by all other non-solar customers

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The Need for a New Cost-Benefit Analysis of NEM

- CPUC's 2009 NEM Study (by E3)
  - Cost of NEM at CSI completion was $137 million/year, 0.4% of IOU revenues.
  - 87% of the net cost shift from NEM was in the residential market, with two-thirds of this shift in the PG&E residential market.
- Rates have changed.
  - Residential rates are significantly different than in 2009, for all IOUs.
- CA 2009 NEM Study used a rate escalation of 4.5% per year.
  - 2010 LTPP forecasts 2011-2030 rate growth of 2.7% per year.
- New perspective on avoided costs
  - Updated input assumptions for the CPUC 's avoided cost model.
  - NEM output reduces IOU sales and avoids RPS generation (20% to 33% of sales).
  - NEM exports increase the share of renewables on the grid (assuming no DG REC sales), because 100% renewable exports displace 20%-33% renewable grid power.

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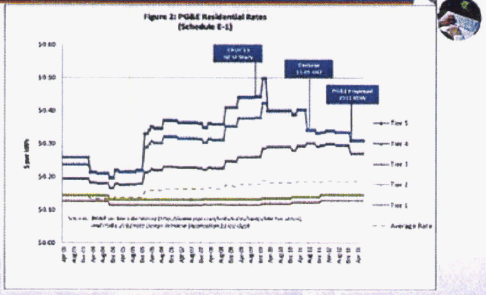
PG&E Rate Changes since 2009



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Major Categories of CPUC- E3 Avoided Cost Benefits

- Energy - All-in CCGT costs less CT-based Capacity costs
  - Uses long-term gas cost forecast based on gas forward market
  - CCGT capital costs include dry cooling and offsets of criteria air pollutants
- Capacity - CT fixed costs
  - Allocated to the top 250 CAISO load hours
- Losses - avoided T&D line losses
- Emissions - avoided GHG allowance costs
  - Synapse forecast of GHG allowance costs
- Ancillary Services - reduced A/S costs due to lower loads
  - A/S costs as a percentage of energy costs, from CAISO data
- T&D - marginal capacity-related T&D costs
  - Allocated on an hourly basis using a temperature-dependent valuation
- Avoided RPS - cost premium for marginal RPS-eligible generation

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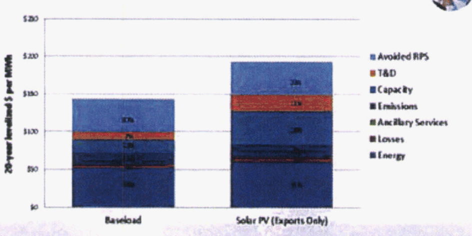
CPUC - E3 Avoided Cost Model: Baseload and Solar PV Profiles



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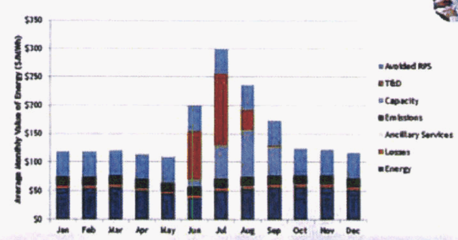
Typical Monthly Avoided Costs (Baseload, CZ 6)



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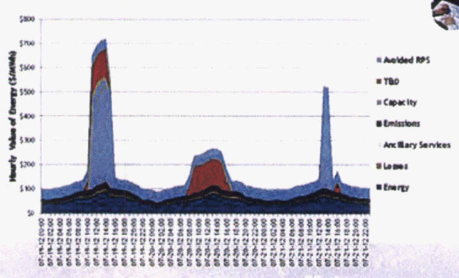
Three-day Hourly Avoided Costs (Baseload, CZ 6)



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New Crossborder NEM Study: Analysis

- Same method as the CPUC's 2009 E3 NEM Study
- Specify the PV customer, and sort similar customers into "bins"
  - Used data from more than 10,000 NEM customers in California
  - Rate schedule
  - Customer pre-solar usage
  - Customer PV system size
  - Location and climate zone
- Hourly analysis compares two cases - A vs. B
  - (A) NEM case: compute annual bill with solar under standard NEM.
  - (B) Reference case: compute annual bill with solar assuming exports in any hour are valued at the hourly avoided cost. Provides ratepayer "indifference."
- If B < A, then NEM is a net benefit to other ratepayers.
- If B > A, then NEM is a net cost to other ratepayers.

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NEM Costs or (Benefits) - $ per kWh Exported Increasing Block, PG&E Climate Zones S, R, P

Annual Customer Usage As a Percent of Baseline												
	500%	$ -	[illegible]	$ 0.181	$ 0.150	$ 0.137	$ 0.116	$ 0.080	$ 0.057	$ 0.035	$ 0.023	$ 0.017
	450%	$ -	[illegible]	$ 0.181	$ 0.148	$ 0.128	$ 0.104	$ 0.072	$ 0.043	$ 0.024	$ 0.011	$ 0.006
	400%	$ -	[illegible]	$ 0.172	$ 0.141	$ 0.115	$ 0.087	$ 0.053	$ 0.027	$ 0.010	$ (0.002)	[illegible]
	350%	$ -	[illegible]	$ 0.166	$ 0.126	$ 0.097	$ 0.062	$ 0.028	$ 0.007	$ (0.007)	$ (0.016)	$ (0.021)
	300%	$ -	[illegible]	$ 0.150	$ 0.098	$ 0.064	$ 0.028	$ (0.002)	$ (0.017)	$ (0.027)	$ (0.034)	[illegible]
	250%	$ -	[illegible]	$ 0.101	$ 0.052	$ 0.008	$ (0.021)	[illegible]	$ (0.040)	[illegible]	[illegible]	[illegible]
	200%	$ -	$ 0.157	$ 0.032	$ (0.020)	$ (0.046)	$ (0.057)	$ (0.063)	$ (0.067)	[illegible]	[illegible]	$ (0.071)
	150%	$ -	$ 0.033	$ (0.040)	[illegible]	$ (0.074)	[illegible]	[illegible]	[illegible]	[illegible]	$ (0.082)	[illegible]
	100%	$ -	$ 0.000	$ (0.049)	$ (0.077)	$ (0.084)	$ (0.086)	$ (0.087)	$ (0.087)	$ (0.087)	[illegible]	[illegible]
	50%	$ -	$ 0.000	$ (0.049)	$ (0.077)	$ (0.084)	$ (0.087)	$ (0.087)	$ (0.087)	$ (0.087)	[illegible]	[illegible]
		10%	20%	30%	40%	50%	60%	70%	80%	90%	100%	110%
		PV System Size (as a percent of Customer's Usage)										

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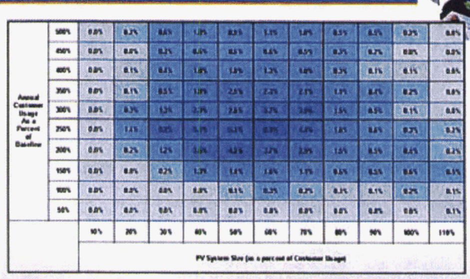
Distribution of NEM Systems PG&E Climate Zones S, R, P



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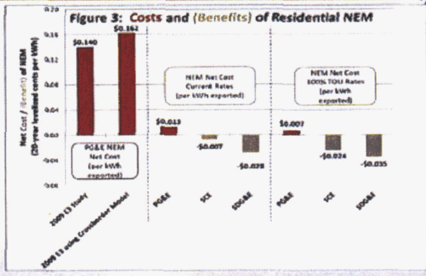
Residential NEM Results (2012$ per kWh exported)



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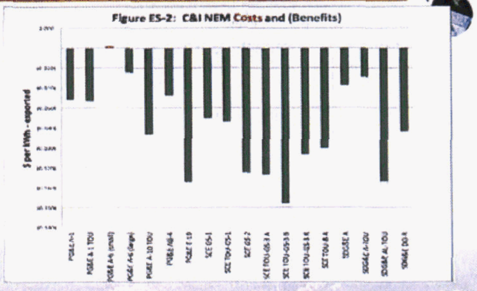
C&I NEM Results (2012$ per kWh exported)



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New Crossborder NEM Study Results Annual Impacts at the 5% NEM Cap (millions, 2012$)

Program	PG&E	SCE	SDG&E	IOU Total
Residential	6.4	(4.2)	(4.3)	(2.1)
C&I	(24.7)	(49.2)	(16.3)	(90.1)
Total	(18.2)	(53.4)	(20.6)	(92.2)

NEM Capacity at the 5% Cap (MW)

Program	PG&E	SCE	SDG&E	IOU Total
Residential	983	914	244	2,141
C&I	1,427	1,325	370	3,122
Total	2,410	2,239	614	5,263

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Sensitivity Results for Residential NEM Annual Impacts at the 5% NEM Cap (millions, 2012$)

Case	Current Mix of IB and TOU Rates	100% TOU Rates
Base	($2.1)	($15.5)
Renewables Premium of 20% (2012) to 33% (2020)	$36.5	$23.1
PV System Sized at 90% of Customer's Usage	($44.5)	($40.2)
1.8%/yr Rate Retail Escalation	($20.1)	($32.7)
4.0%/yr Rate Retail Escalation	$27.0	($12.2)
Incremental Billing Costs of $0.01 per kWh	$9.9	($3.4)

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Crossborder NEM Study Results Total NEM Annual Impacts, 20%-33% Renewable Premium Sensitivity (millions, 2012$)

Program	IOU Total
Residential	$36.5
C&I	($53.0)
Total	($16.5)

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Key Conclusions

- NEM is cost-effective.
  - A small net cost in the PG&E residential market is outweighed by...
  - ...small net benefits in the SCE and SDG&E residential markets.
  - C&I NEM produces significant net benefits.
  - Even with a lower (20%-33%) renewables premium, the net impact of NEM across all markets is a net benefit.
- Rate design has significant impacts on NEM economics
  - A move to greater use of existing TOU rates would increase NEM benefits for non-participating ratepayers.
  - Simpler TOU rate designs have larger benefits than more complex ones.
  - C&I rates that reduce demand charges will reduce cost shifts from solar customers to non-participating ratepayers.

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Resource Planning & Distributed Energy

Bob Davis
Principal & Executive Consultant
nFront Consulting

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Utility Resource Planning & Solar Distributed Energy

- Electric utilities are responsible for providing reliable power at low cost
  - Dependable and dispatchable resources
  - Lowest reasonable cost through balance of resource capital costs, efficiency, fuel price
  - Low-priced fuel sources balanced with minimizing environmental impacts
  - Fuel diversity, technology diversity, risk management

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Utility Resource Planning & Solar Distributed Energy

- Regulations may require utility-sponsored load reduction programs
  - Mandated targets or cost-effectiveness evaluations
  - Mandate specific program types:
    - Energy efficiency / DSM
    - Renewable resources
    - Renewable distributed energy

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Utility Resource Planning & Solar Distributed Energy

APS Renewable Energy & Energy Efficiency Targets (% of Retail Sales)	Renewable Energy	Distributed Energy	Energy Efficiency
Target:			
2015	5.0%*	1.5%**	9.5%
2020	10.0%	3.0%**	22.0%
2025	15.0%	4.5%**	22.0%
Planned (from 2012 IRP and Solar DE Update):			
2015	11.6%	1.5%***	9.5%
2020	12.5%	4.6%***	22.0%
2025	17.2%	8.0%***	22.0%

* Excludes 1,700 GWh increment for 2015. ** Represents 30% of total renewable target.

*** Represents assumptions for Solar DE Update, Expected Case.

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Utility Resource Planning & Solar Distributed Energy

- Utilities will typically consider load reduction programs if they pass certain cost-effectiveness thresholds (or tests)
  - Reduces total utility costs
    - ➢Utility Cost Test
  - Reduce utility rates of all customers
    - ➢Rate Impact Measure Test (or RIM)
  - Reduces total costs to the community
    - ➢Total Resource Cost Test (or TRC)

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Cost-effectiveness Standard Practice Tests

	Utility	RIM	TRC
Benefits:			
Avoided Utility Energy Costs	✓	✓	✓
Avoided Utility Capital Costs	✓	✓	✓
Avoided Utility O&M Costs	✓	✓	✓
Customer Tax Credits			✓
Costs:			
Lost Retail Revenue		✓	
Utility Program Administrative Costs	✓	✓	✓
Utility Incentives Paid to Customers	✓	✓	
Participant Costs (Equip. and O&M)			✓

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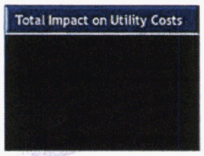
Impact of Solar DE on Generation Operations and Planning

How does Solar DE impact utility operations and planning of generating resources?

- Changes utility load shape
  - ➡ Changes generation dispatch
- Reduces peak demands
  - ➡ Reduces need for future capacity additions
- May cause cost increases
  - Need for firming capacity
  - Delayed implementation of other high-efficiency resources
  - Increased need for operating reserves

Total Impact on Utility Costs



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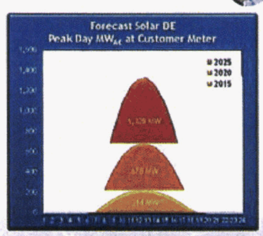
Development forecast of Solar DE Implementation

- Develop representation of typical hourly Solar DE production
  - Simulation of Solar DE resource output for a typical meteorological year
  - Diversified sample of historical production for actual resources
- Forecast of Solar DE implementation



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Adjustments of Solar DE Production for Electric System Losses

- Losses occur on the electric grid from the generator to the customer
  - Peak demand losses (11.7%)
  - Energy losses (7.0%)
- To evaluate Solar DE production equivalent to generating units:
  - Solar DE production at the customer site is adjusted upward to a level equal to the load met by generating units by dividing by (1 - loss rate)

Example Solar DE Adjusted for Electric System Losses 2015	Nameplate Capacity (MW)	Annual Energy Production (GWh)
Solar DE at the customer meter	214	401
Loss adjustment	1.133	1.075
Solar DE measured at the generation bus	242	431

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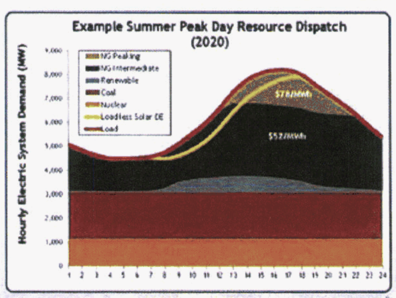
Avoided Marginal Energy Costs



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Avoided Marginal Energy Costs

What energy costs can be avoided by Solar DE?

Example Avoided Energy Costs 2020			
Generating Unit Variable Operating Costs	Units	Combined Cycle	Combustion Turbine
Average heat rate	Btu/kWh	6,800	10,300
NG Fuel price	$/MMBtu	5.82	5.82
Avoided fuel cost	$/MWh	39.58	59.95
Variable O&M	$/MWh	5.06	6.71
Emission costs	$/MWh	6.99	9.31
Avoided start-up costs	$/MWh	0.49	1.66
Total avoided variable operating cost	$/MWh	52.12	77.62

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Avoided Marginal Energy Costs

How do utilities simulate and project marginal energy costs?

- Generation dispatch simulation using industry-standard model
  - Depict operating characteristics of generating and purchased power resources
    - Min/max capacity
    - Heat rate curves
    - Variable O&M
    - Emission rates
    - Start fuel / costs
    - Operating limitations
  - Fuel price forecast
  - Forecast of hourly loads (multiple years)
  - Simulate generation commitment and dispatch to serve hourly load
- Perform simulation with and without Solar DE impact on load
- Using results for two cases: compute change in energy costs divided by change in load ($/MWh)

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Avoided Generation Capacity Costs

What generation capacity costs can be avoided by Solar DE?

- Avoided capacity-related costs:
  - Capital costs of avoided or deferred generating units
  - Capital cost of transmission interconnections for the avoided or deferred generating units
  - Fixed O&M costs of the avoided or deferred generating units
  - Natural gas pipeline reservation fees for the avoided or deferred generating units
  - Avoided purchased power capacity
- Incurred capacity-related costs:
  - Backup capacity / integration costs
  - May result in delayed installation of high-efficiency generating resources that otherwise would have reduced energy costs for the utility

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Avoided Generation Capacity Costs

How are avoided generation capacity costs developed?

- Determine utility capacity need
- Evaluate cost-effective generating capacity additions
- Determine impact of Solar DE on capacity
  - Forecast installed Solar DE capacity
  - Adjust Solar DE capacity for losses and dependable capacity
- Identify future generating resources that can be avoided by Solar DE
- Calculate generating unit costs that can be avoided or deferred

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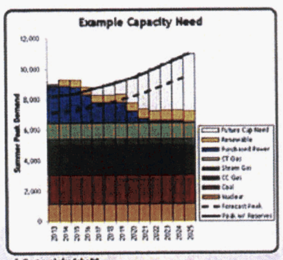
Utility Capacity Requirements



* Chart excludes Solar DE.

- Determination of capacity need
  - Forecast peak demand
  - Planning reserves
  - Existing and committed future resources
  - Planned regulatory resources and customer programs
  - Net capacity need

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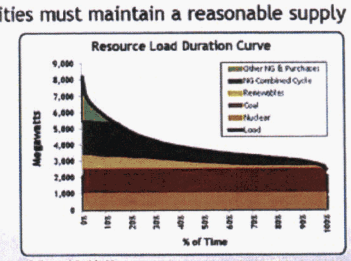
Evaluation of Utility Capacity Additions

Utilities must maintain a reasonable supply mix



* Chart excludes Solar DE.

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Evaluation of Capacity Additions

- Economic simulation and optimization of planned future resource additions
  - Generation simulation / portfolio scenario analysis (e.g., PROMOD)
  - Generation simulation / dynamic optimization (e.g., STRATEGIST)
  - Generation simulation / probabilistic analysis (e.g., MarketPower)
  - Portfolio market valuation (e.g., AURORA)
  - Each modeling approach has pros and cons - no clear benefit of one approach over another

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Impact of Solar DE on Utility Capacity Additions

- Dependable capacity of Solar DE
  - Adjusted for capacity losses (increased to generation bus)
  - Effective load carrying capability (ELCC)
  - Coincidence with the electric system peak
  - Diminishing capacity value with increasing penetration
- Solar DE should be compared against similarly performing generating resources when considering avoided capacity

Comparison of Annual Capacity Factors			
Solar DE	New Combustion Turbine	New Combined Cycle	Baseload Resources
20%	15% - 20%	50% - 60%	70% - 90%

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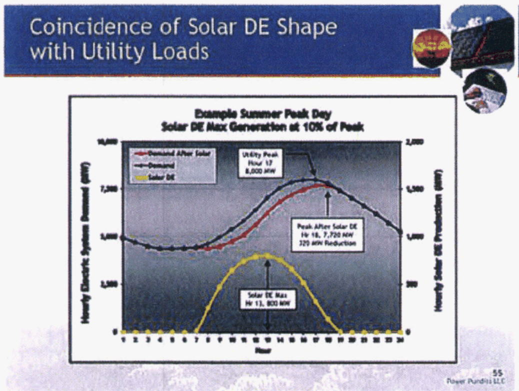
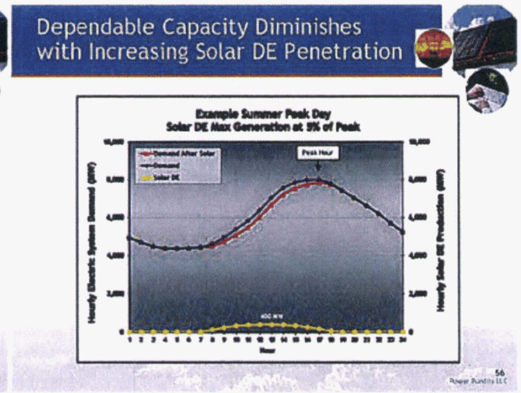
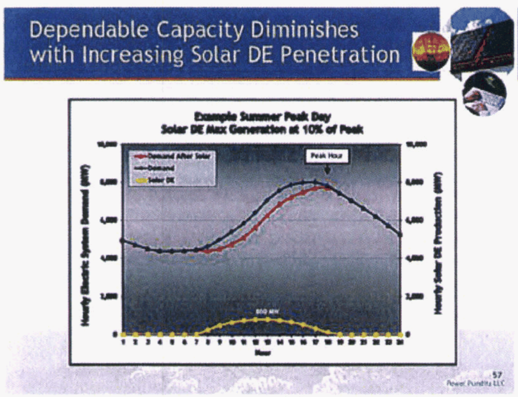
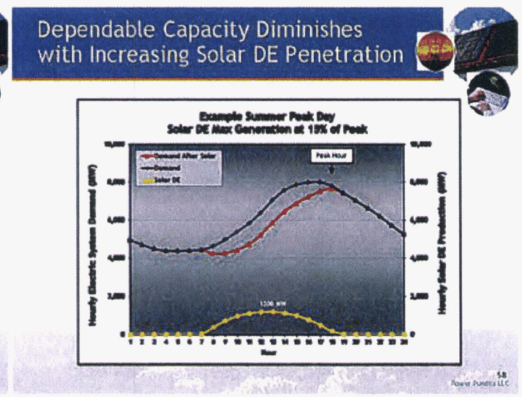
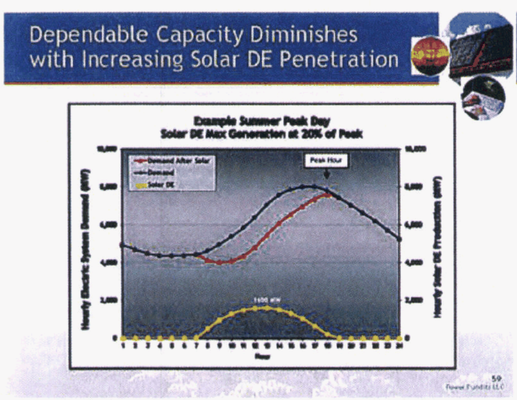
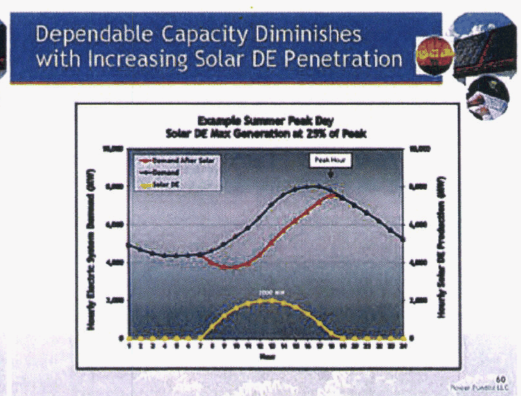

Coincidence of Solar DE Shape with Utility Loads
Example Summer Peak Day
Solar DE Max Generation at 10% of Peak
55

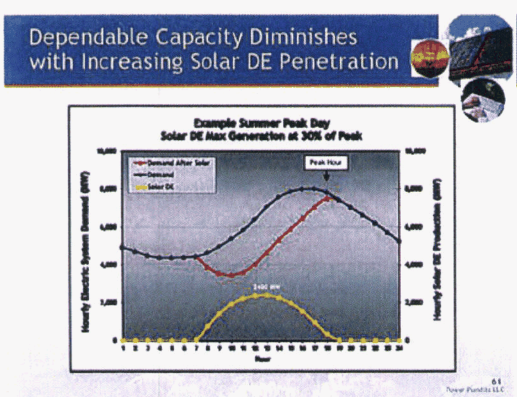

Dependable Capacity Diminishes with Increasing Solar DE Penetration
Example Summer Peak Day
Solar DE Max Generation at 5% of Peak
Peak Hour
56

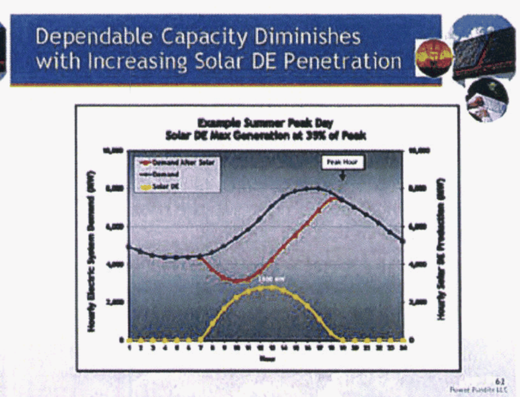

Dependable Capacity Diminishes with Increasing Solar DE Penetration
Example Summer Peak Day
Solar DE Max Generation at 10% of Peak
Peak Hour
57


Dependable Capacity Diminishes with Increasing Solar DE Penetration
Example Summer Peak Day
Solar DE Max Generation at 15% of Peak
Peak Hour
58

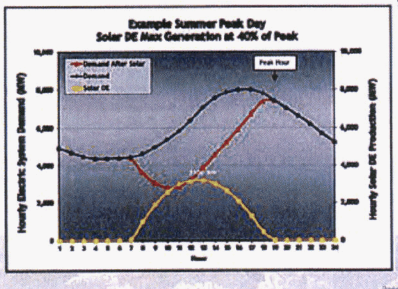

Dependable Capacity Diminishes with Increasing Solar DE Penetration
Example Summer Peak Day
Solar DE Max Generation at 20% of Peak
Peak Hour
59


Dependable Capacity Diminishes with Increasing Solar DE Penetration
Example Summer Peak Day
Solar DE Max Generation at 25% of Peak
Peak Hour
60


Dependable Capacity Diminishes with Increasing Solar DE Penetration
Example Summer Peak Day
Solar DE Max Generation at 30% of Peak
Peak Hour
61


Dependable Capacity Diminishes with Increasing Solar DE Penetration
Example Summer Peak Day
Solar DE Max Generation at 35% of Peak
Peak Hour
62

Dependable Capacity Diminishes with Increasing Solar DE Penetration



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Dependable Solar DE Capacity

Example Solar DE Dependable Capacity Calculation Expected Case - 2015	Adjustment Percent	Multiplier	Adjusted Capacity
Solar DE nameplate capacity (MW_{AC} at meter)			214 MW
Technology diversity	99.4%	0.994	
Peak demand losses	11.7%	1.133	
Dependable capacity adjustment	50%	0.500	
Diminishing value of incremental additions	92.0%	0.920	
Net dependable capacity (MW at the generator bus)		0.518	111 MW

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Avoided Utility Capacity Costs

Example Avoided Cost of Capacity in 2020	2013 $/kW	Annual $/kW-yr
CT capital cost	1,127	147.40
Transmission interconnection	200	26.20
Fixed O&M		9.30
NG reservation charges		16.40
Total CT fixed charges		199.30

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Estimates of Avoided Energy and Capacity Costs May not be Fully Achievable

Avoided energy costs may be lower than the example values shown

- As larger quantities of Solar DE are installed:
  - It becomes more difficult to accommodate the Solar DE resources in the generation dispatch
  - Inefficient dispatch operations can result
    - Generating units may be cycled more than usual
    - Generating units may be forced to operate at part-load (less efficient fuel use)
  - Lower-cost coal resources may be turned down during non-summer periods, instead of higher-cost natural gas resources
    - Reduces the value of avoided energy costs

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Estimates of Avoided Energy and Capacity Costs May not be Fully Achievable

Avoided capacity costs may be lower than the example values shown

- Utility capacity costs are reduced only when a generating unit is truly avoided or deferred
- Solar DE installations may not be timed consistent with the utility plans for generation additions
- Solar DE installations must accrue until they are large enough to avoid or defer a unit
  - Surplus Solar DE capacity may be in place in some years
  - Any surplus does not reduce utility capacity costs (but still reduces energy costs)

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Solar DE Total Avoided Cost

Example - Total Avoided Cost			
Solar DE Capacity and Energy	2015	2020	2025
Nameplate capacity (MW AC at meter)	214	678	1328
Demand loss adjustment factor	1.133	1.133	1.133
Dependable capacity adjustment factor	0.459	0.306	0.210
Dependable capacity (MW at gen bus)	111	235	316
Annual energy production (GWh AC at meter)	400	1,302	2,548
Annual energy production (GWh at gen bus)	430	1,400	2,740
Avoided Costs	2015	2020	2025
Avoided capacity costs ($/kW-yr)	--	199.30	225.50
Avoided energy costs ($/MWh)	35.41	54.78	72.23
Conservative adjustment factor	80%	80%	80%
Total avoided cost ($M)	$12.2	$95.8	$206.9
Average avoided costs (¢/kWh at meter)	3.0¢	7.4¢	8.1¢

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Conclusions

- Solar DE has the potential to avoid both energy and capacity related generating costs of the utility
- Consideration must be given to the true dependable capacity of Solar DE
- Solar DE can introduce inefficiencies into the dispatch operations of the utility
- Future Solar DE and generating unit installations may have different schedules and magnitudes, which can lower the capacity value of Solar DE

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APS Resource Planning

Paul Smith

Arizona Public Service

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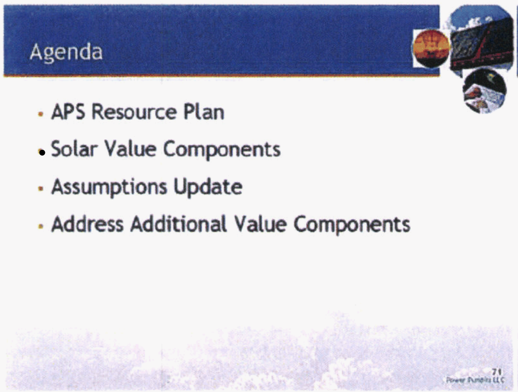
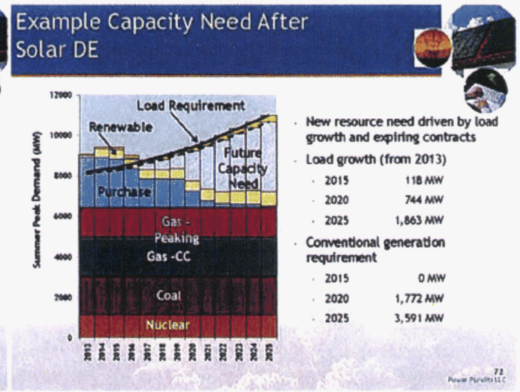
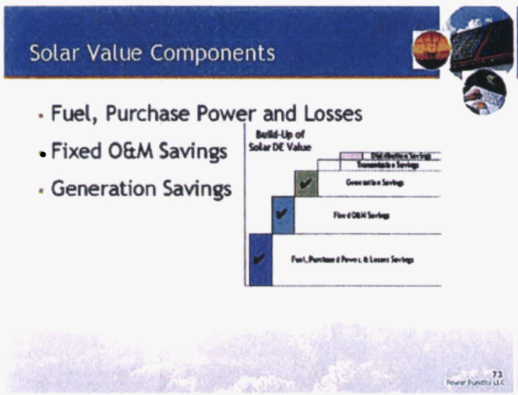
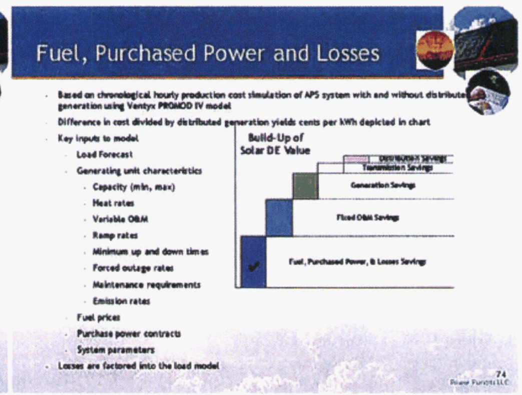
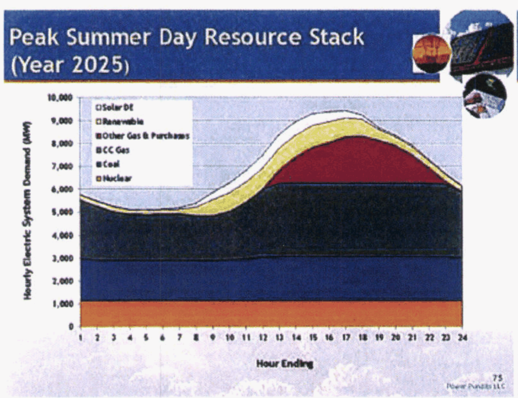
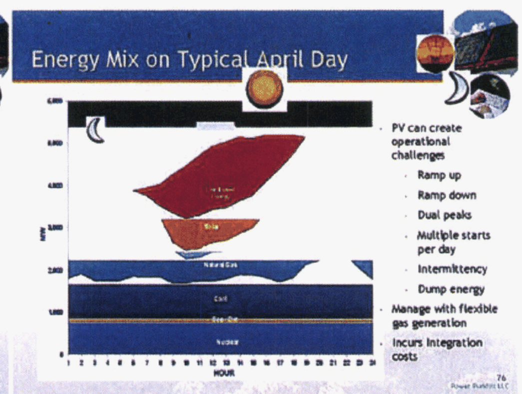

Agenda
APS Resource Plan
Solar Value Components
Assumptions Update
Address Additional Value Components
71

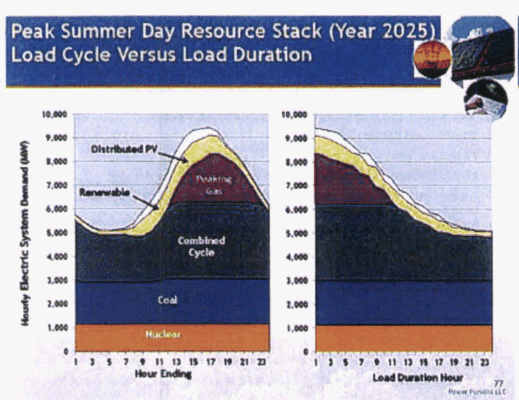

Example Capacity Need After Solar DE
Load Requirement
Renewable
Future Capacity Need
Purchase
Gas - Peaking
Gas -CC
Coal
Nuclear
Summer Peak Demand (MW)
New resource need driven by load growth and expiring contracts
Load growth (from 2013)
2015 118 MW
2020 744 MW
2025 1,863 MW
Conventional generation requirement
2015 0 MW
2020 1,772 MW
2025 3,591 MW
72

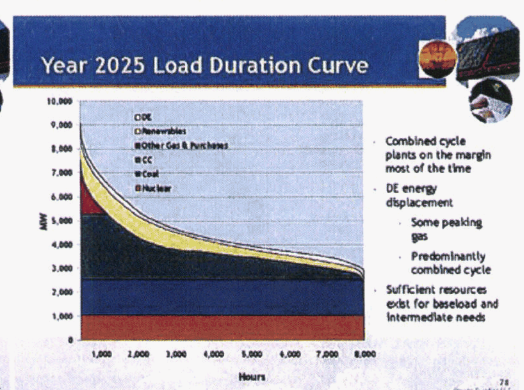

Solar Value Components
Fuel, Purchase Power and Losses
Fixed O&M Savings
Generation Savings
Build-Up of Solar DE Value
Generation Savings
Fixed O&M Savings
73


Fuel, Purchased Power and Losses
Based on chronological hourly production cost simulation of APS system with and without distributed generation using Ventyx PROMOD IV model
Difference in cost divided by distributed generation yields cents per kWh depicted in chart
Key inputs to model
Load Forecast
Generating unit characteristics
Capacity (min, max)
Heat rates
Variable O&M
Ramp rates
Minimum up and down times
Forced outage rates
Maintenance requirements
Emission rates
Fuel prices
Purchase power contracts
System parameters
Losses are factored into the load model
Build-Up of Solar DE Value
Generation Savings
Fixed O&M Savings
Fuel, Purchased Power, & Losses Savings
74


Peak Summer Day Resource Stack (Year 2025)
Solar DE
Renewable
Other Gas & Purchases
CC Gas
Coal
Nuclear
Hourly Electric System Demand (MW)
Hour Ending
75


Energy Mix on Typical April Day
PV can create operational challenges
Ramp up
Ramp down
Dual peaks
Multiple starts per day
Intermittency
Dump energy
Manage with flexible gas generation
Incurs integration costs
MW
HOUR
76


Peak Summer Day Resource Stack (Year 2025) Load Cycle Versus Load Duration
Distributed PV
Renewable
Peaking Gas
Combined Cycle
Coal
Nuclear
Hourly Electric System Demand (MW)
Hour Ending
Load Duration Hour
77


Year 2025 Load Duration Curve
DE
Renewables
Other Gas & Purchases
CC
Coal
Nuclear
MW
Hours
Combined cycle plants on the margin most of the time
DE energy displacement
Some peaking gas
Predominantly combined cycle
Sufficient resources exist for baseload and intermediate needs
78

Key Drivers of Avoided Energy Cost

- Load forecast
  - Customer growth
  - Energy efficiency standard
  - Distributed generation
- Fuel prices, especially natural gas
- Environmental costs (carbon)

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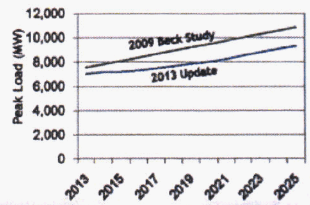
Load Forecast (Prior to DE)



- Current load forecast down primarily due to slower economy
  - 2015 900MW
  - 2025 1,550 MW

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Distributed Energy Scenarios Nameplate MW_{AC}

2009 Beck Study	Low	Expected	High
2015	33	68	68
2025	52	873	1,915

2013 Update	Low	Expected	High
2015	166	282	242
2020	338	768	971
2025	734	1,504	3,044

2013 update

- Low sensitivity - based on compliance with RES
- Expected case - APS current estimate
- High sensitivity - Approximately 2 times expected case

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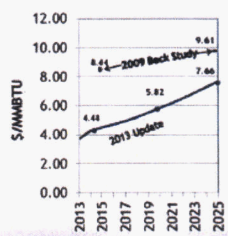
Natural Gas Price Forecast



- Based on market forward gas curve 12/31/2012
- Volatility managed through three year hedge plan
  - Year 1 - 85%
  - Year 2 - 50-60%
  - Year 3 - 30-40%
- Lower gas prices reduce avoided energy value

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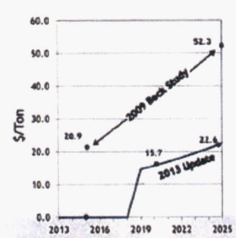
Carbon Price Forecast



- Based on Charles River Associates recommendation for APS 2012 IRP
- Assumes carbon legislation takes effect in 2019 at approximately 15 $/ton, escalating 5% above inflation
- Lower carbon prices reduce avoided energy value
- Inclusion of carbon adds 0.8 to 1.2 cents per kWh to avoided energy costs

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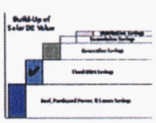
Fixed O&M

- Fixed operating and maintenance cost of avoided generating capacity
  - Simple cycle combustion turbine
    - 2013 update 5.3 $/kW-yr
    - 2009 Beck 7.3 $/kW-yr
- Fixed gas transport charges
  - Based on gas consumption of combustion turbine and pipeline tariff
    - 2013 update 27.14 $/Dth-mo
    - 2009 Beck 13.6 $/Dth-mo
- 2009 Beck Study included purchase power demand charges
  - 2013 update includes them in "Generation Savings"



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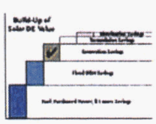
Generation

- Generation cost is based on avoidance of new combustion turbine generating capacity and avoidance of purchase power
  - 2009 Beck 1006 $/kW
  - 2013 update 1136 $/kW
- APS IRP indicates need for new generation beginning in 2017
- Amount of new generation deferred due to distributed generation based on effective load carrying capability (ELCC) of distributed generation
  - ELCC is a reliability based probabilistic analysis correlating solar production and load profile
  - Dependable capacity is related to penetration of DG



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Solar Capacity Valuation

- APS uses industry best practice methodology to value solar capacity
  - Effective Load Carrying Capability (ELCC)
  - Probabilistic methodology
  - Chronologically matches utility load and solar production on hourly basis
  - Capacity value is dependent on solar penetration, i.e., as penetration increases, capacity value decreases
  - Capacity value is based on solar contribution over many high load hours, not just the peak hour
- Illustrative examples developed using actual load and solar production data from summer 2012
  - Peak day Aug. 8, 2012
  - Six operating solar plants
    - Nameplate value 78 MW
  - Example is for predominantly single axis tracking utility scale systems
  - Distributed systems would have lower capacity value
  - Principle is the same

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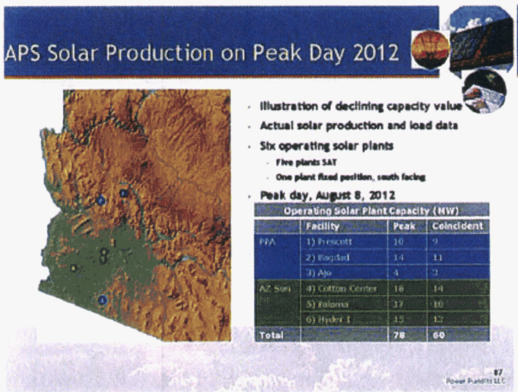
APS Solar Production on Peak Day 2012
Illustration of declining capacity value
Actual solar production and load data
Six operating solar plants
Five plants SAT
One plant fixed position, south facing
Peak day, August 8, 2012
Operating Solar Plant Capacity (MW)
Facility | Peak | Coincident
PPA 1) Prescott 10 9
2) Bagdad 14 11
3) Ajo 4 3
AZ Sun 4) Cotton Center 18 14
5) Paloma 17 10
6) Hyder I 15 13
Total 78 60
87
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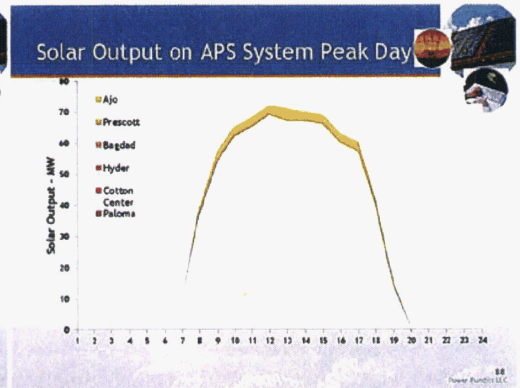
Solar Output on APS System Peak Day
Ajo
Prescott
Bagdad
Hyder
Cotton Center
Paloma
Solar Output - MW
88
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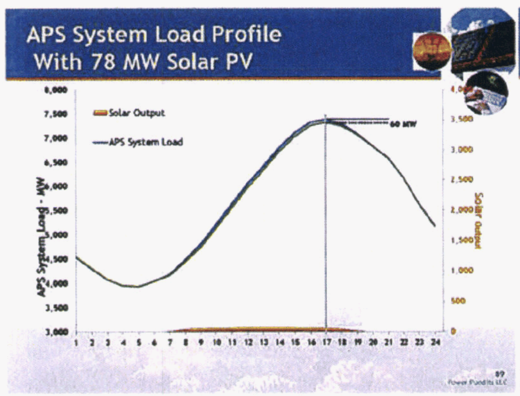
APS System Load Profile With 78 MW Solar PV
Solar Output
APS System Load
60 MW
APS System Load - MW
Solar Output
89
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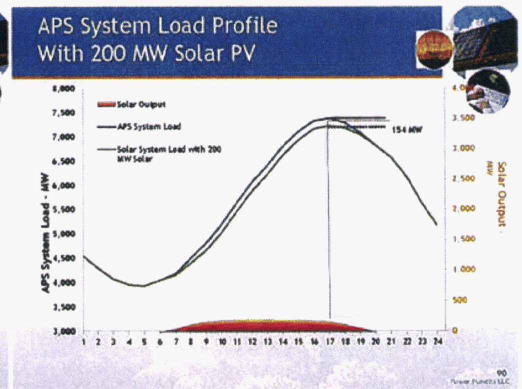
APS System Load Profile With 200 MW Solar PV
Solar Output
APS System Load
Solar System Load with 200 MW Solar
154 MW
APS System Load - MW
Solar Output - MW
90
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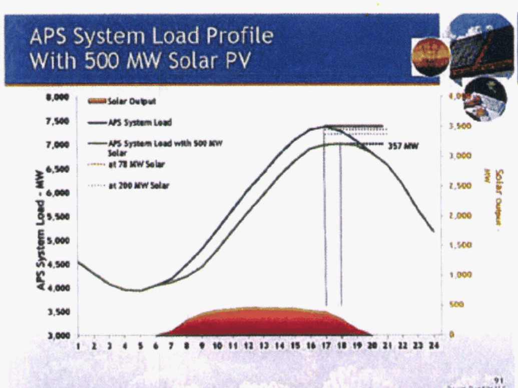
APS System Load Profile With 500 MW Solar PV
Solar Output
APS System Load
APS System Load with 500 MW Solar
at 78 MW Solar
at 200 MW Solar
357 MW
APS System Load - MW
Solar Output - MW
91
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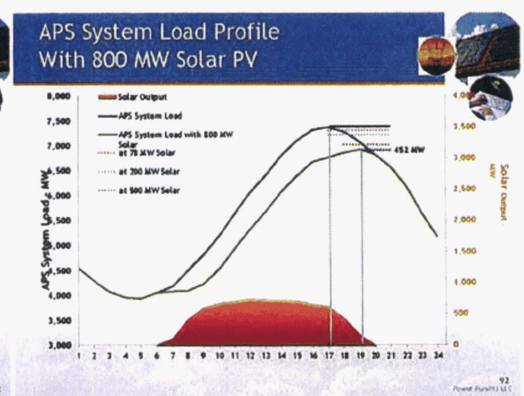
APS System Load Profile With 800 MW Solar PV
Solar Output
APS System Load
APS System Load with 800 MW Solar
at 78 MW Solar
at 200 MW Solar
at 500 MW Solar
452 MW
APS System Load - MW
Solar Output - MW
92
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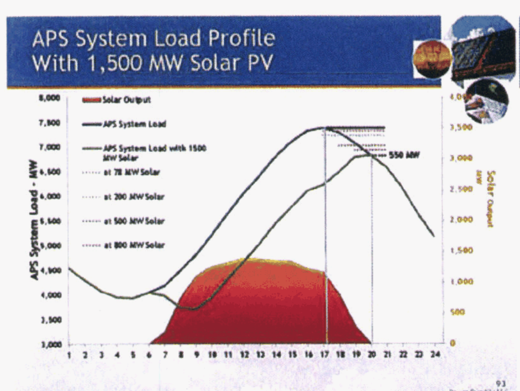
APS System Load Profile With 1,500 MW Solar PV
Solar Output
APS System Load
APS System Load with 1500 MW Solar
at 78 MW Solar
at 200 MW Solar
at 500 MW Solar
at 800 MW Solar
550 MW
APS System Load - MW
Solar Output - MW
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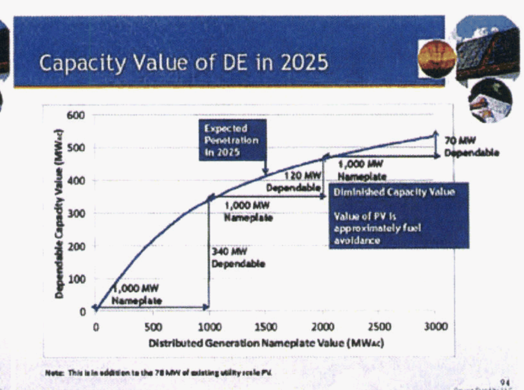
Capacity Value of DE in 2025
Expected Penetration in 2025
70 MW Dependable
1,000 MW Nameplate
120 MW Dependable
Diminished Capacity Value
1,000 MW Nameplate
Value of PV is approximately fuel avoidance
340 MW Dependable
1,000 MW Nameplate
Dependable Capacity Value (MWac)
Distributed Generation Nameplate Value (MWac)
Note: This is in addition to the 78 MW of existing utility scale PV.
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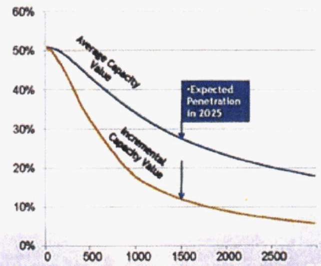
Capacity Value Decreases With Increasing Penetration (2025)



- At high penetration, value of solar is approximately fuel avoidance

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Additional data considerations

- Market price mitigation
- Benefits from southwest or west facing orientations of fixed arrays
- Grid security benefits
- Fuel hedge value
- Environmental compliance savings
- Reliability benefits
- Avoided RPS wholesale purchases

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APS Cost and Benefit Considerations

- Must accrue real, measurable benefits to our customers
- Impacts must be recognized in cost of service ratemaking
  - Test year versus future looking
- Does not include societal benefits / externalities

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Market Price Mitigation

- Stakeholder comment
  - Direct cost savings due to reduction in load. Indirect value of market price reduction, and natural gas price reduction.
- Response
  - Direct cost savings to APS customers already captured in avoided cost analysis
  - Indirect value is theoretically possible
    - Impact on regional/national natural gas market difficult to quantify
    - Market rebalances itself (supply & demand)
    - APS does not operate in an LMP market, difficult to quantify
    - Price elasticity difficult to quantify
    - APS is both buyer and seller, so it is not clear what the net effect would be

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Benefits From Southwest or West Facing Orientations of Fixed Arrays

- Stakeholder comment
  - Southwest or west facing systems peak later in the day and have higher capacity value, generate less annual energy than south or horizontal systems
- Response
  - APS recognizes that orientation of fixed arrays may affect value
  - West / Southwest orientation versus south
    - Increased capacity value
    - Decreased energy value

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Grid Security Benefits

- Stakeholder comment
  - Injection of PV energy near the point of use reduces loss of load probability (LOLP), and therefore the risk of power outage and rolling blackouts that are caused by high demand and resulting stresses on the transmission and distribution systems
- Response
  - This is already included in APS capacity value calculation through the ELCC methodology
  - Reserve margins already account for reliability of DE

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Fuel Hedge Value

- Stakeholder comment
  - Solar generation offers a hedge against fuel price volatility and uncertainty. The value should be based on long term futures contracts.
- Response
  - Hedge value benefits individual participants, not non-participants
  - APS currently uses future contracts for the price of natural gas
    - APS uses long term future contracts in long term integrated resource planning
    - APS power supply adjuster reflects short term natural gas costs
  - APS currently has a three year hedge program
    - Beyond three years volatility is diminished

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Environmental Compliance Savings

- Stakeholder comment
  - Use of solar DE reduces power plant emissions and water use
- Response
  - Avoided cost already includes controls to meet environmental requirements and water use
  - APS quantifies reductions in power plant emissions and water use in its IRP

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Reliability Benefits

- Stakeholder comment
  - Use of solar DE reduces utility load, and therefore reduces the utility's spinning and non spinning reserve requirements
- Response
  - Spinning reserve requirements are an input to APS production costing model, and therefore this impact is included in avoided energy cost
  - Increased solar DE can also increase spinning reserve requirements due to intermittency of solar production

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Avoided RPS Wholesale Purchases

- Stakeholder comment
  - Solar DE avoids wholesale purchases that would otherwise be required to meet Resource Portfolio Standards
- Response
  - This would be a benefit when RPS purchases are required if the cost is above conventional power cost
  - No value beyond compliance

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Participation Processes

✔	Opening Forum Creating a common set of expectations	February 21, 2013
	Workshops Detailed examination of the methodologies	
✔	Understanding Rates and DE Benefits	March 7, 2013
➡	Resource Planning and DE Costs	March 20, 2013
	SAIC Study and Other Models	April 11, 2013
	DE Business Cases & Related Analysis	April 25, 2013
	DE Business Cases & Related Analysis	May 9, 2013
	Closing Forum	TBD

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Next Steps

- www.solarfuturearizona.com will be populated
- Material from today's presentation will be posted this evening
- Questions will be collated and matched to upcoming workshops

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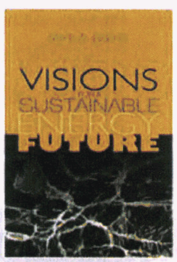
Questions?



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Meeting Notes

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Decision and Process Advisement in Energy and Water

TO: APS Workshop 2 Participants

FROM: Power Pundits LLC

RE: Workshop 2

DATE: April 12, 2013

As ordered by the Arizona Corporation Commission related to its 2013 Renewable Energy Standard Implementation Plan, Arizona Public Service Company conducting a multi-session Technical Conference with stakeholders to evaluate the costs and benefits of distributed renewable energy and net metering. The sessions are designed to bring together stakeholders holding a wide range of perspectives, experiences, and levels of technical knowledge to evaluate these costs for all customers—both those who have access to distributed energy and those who do not. Sessions are exploring such issues as environmental mandates, changes in generation requirements resulting from adding distributed energy to the generation stack, localized grid impacts, system losses and other relevant topics. APS engaged Mark Gabriel and his team at Power Pundits LLC to lead, moderate, and manage this technical conference.

Meetings in this series to date have included an opening forum held February 21, a technical workshop on understanding rates and distributed energy (DE) benefits held March 7, a follow-up stakeholder call on March 14, and the second workshop, documented here, held on March 20 at the APS Learning Center in downtown Phoenix.

Workshop 2 explored the topics of resource planning and DE costs. Topics discussed were:

- Case Study on Evaluating the Benefits and Costs of Net Energy Metering in California, from Crossborder Energy
- Fundamentals of Resource Planning and Distributed Energy
- APS Resource Planning and Distributed Energy

Fifty-three stakeholders registered for this forum, including nine people who participated via a conference phone connection.

Copies of the agenda and presentation slides are available at www.solarfuturearizona.com. An audio recording of the workshop is also available on the site. These notes are the reflection of Power Pundits staff who participated in the workshop and are not a verbatim record. We believe they accurately reflect the sense of the day's meeting.

➢ In these meeting notes, **action items** are indicated by an arrow before the item.

Welcome and Workshop Overview
Mark Gabriel, Power Pundits
Slides 1 - 8

Mark Gabriel introduced himself, saying that he was part of the R.W. Beck study in the past and is now principal at Power Pundits. He mentioned safety concerns for the day. He promised to make sure everyone gets heard, and noted that there are several people on the phone as well. Please send questions and comments to techconf@aps.com or lavernekyriss@powerpundits.com. All the participants introduced themselves, answering the questions, "Do you remember your first cell phone, and do you have a land line?" This exercise demonstrated the point that phone service is now largely "distributed" rather than centralized.

Mr. Gabriel said that questions and promised data from the last meeting are posted on the web site. He asked that all participants:

- Please provide the names of any speakers you'd like for future meetings to LaVerne Kyriss, by next Wednesday, March 27.
- Please send data requests by April 11, considered a soft cutoff, so we have time to answer them.

The next workshops will be held on April 11, April 25, and May 9, and the closing forum will be later in May. He summarized a conference call that was held last Thursday, March 14, where there were quite few participants and good discussion – call notes will be posted soon.

Mr. Gabriel reviewed the goals of the workshops. He stressed that there are no pre-determined outcomes from this process. He reviewed the ground rules for this meeting, the stakeholder engagement process and schedule, and the agenda for today.

Participants had some questions and comments on the summary of key points from Workshop 1 (see slide 8).

Qs & As:

- **What does "unique load profile" mean?**

Load profiles are different among standard customers, with and without DE.

- **Several questioned the statement that APS service is highly driven by fixed costs.**

All costs change over time, so in that respect they're all variable; but fixed costs are capacity costs like power plants and transmission lines that don't change with customer kilowatt (kW) usages.

- **On a slide from Workshop 1 showing cost structure vs. revenue collection (slide 30) how did APS get to be so out of balance on rate setting?**

This is an artifact of a 60-year-old rate design. Historically, residential service was kWhour-based, and utilities didn't worry so much about demand costs. In the last four or five years, this is becoming an issue and APS now has meters that can measure demand and energy.

Participant Comments and Observations

- Many of these costs are also true of photovoltaic (PV) technology; power plant costs are time-limited.
- APS rate-setting may be based on historical [test] year but are intended to recover costs that occur during the period the rates are in effect.

Opportunities for Alignment
Mark Gabriel, Power Pundits
Slides 9-12

Mr. Gabriel reminded the group that alignment means understanding of the issue and willingness to support the group's definition. He reviewed the three topics from the last meeting that participants felt needed further work for alignment to be reached. In response to a question, he clarified that in the final report, aligned items will be described as ones that everyone agrees with, but there will be statements on any disagreements.

Participants indicated that they are aligned on one of these topics, a definition of net metering:

> Net metering is a billing mechanism that credits solar system owners for the electricity exported onto the grid. Under the simplest implementation of net metering, a utility customer's billing meter runs backward as solar energy is generated and exported to the electricity grid and forward as electricity is consumed from the grid.

Participants were mixed in their alignment of the statement:

- Solar energy provides economic development opportunities in AZ.
  Participants said:
  - Make the statement less strong, because while solar energy did provide opportunities in past, the current incentive situation and economy has negatively affected the industry.
  - Conversely, "opportunities" imply future, so the wording is good.
  - Solar energy is big worldwide, but three years ago APS put $40 million into distributed generation [referring to APS' incentive budget], cut to $24 million, and to $3 million this year.

Participants concluded that they are not aligned on the issue of rate fairness, as worded:

- Rates need to consider impacts to DE participants and non-participants, while supporting utility cost recovery.
  Participants said:
  - I am not aligned with this statement.
  - I strongly agree that rates need to be fair to all.
  - Suggest looking at alignment based on rate classification; for example, the mining industry uses a lot of power but contributes little to rates.
  - Suggest the wording, "Rates need to consider impacts on customer classes while supporting utility cost recovery."

- What about restaurants, whose use profile is different from the general class of small commercial?
- Rate design and net metering are different things. Rate design is handled through rate cases, and includes a myriad of issues that are fundamentally different from net metering. All can agree that rate design and rate philosophy matter, that's not the same a net metering. A rate discussion needs to include a whole host of public policy issues, of which DE is only a small part.
- The utility needs to think about the whole rate structure and how it is derived; for example, in the future should they be able to recover costs of electricity that's not used?
- Suggest the wording could be "should consider" rather than "need to consider" and use word "effects" rather than "impacts," which has a negative connotation.

Mr. Gabriel led a discussion on additional opportunities for alignment (slide 12):

Participants were aligned on four topics:

- DE rate impacts can occur through behind the meter rate offsets (self supply) as well as net metering bill credits.
- APS rates are based on historical test years.
- DE impacts both costs to serve and revenues collected.
- DE customers have a unique load profile, benefits and costs.

Participants are not aligned on two topics:

- APS service is highly driven by fixed costs.

Participants said:

- What part of APS is driven by fixed costs?

A: Provision of service to customers

- Some stakeholders noted they were not aligned unless a timeframe is provided.
- The disagreement may be on how you define fixed costs. There seem to be different opinions. Suggest using investment-related fixed costs as the utility definition of fixed costs, rather than an economists' definition.
- This implies that fixed costs can't be changed, and that's not true. This statement is too cursory.
- Alignment might be reached if the statement said that this refers to mostly fixed costs in the short run and acknowledged the possibility of lower fixed costs in the future.
- Fixed costs are, to an extent, a choice made by utilities; e.g. to invest in a power plant rather than buying [power] on the open market.

- For residential and small commercial rate categories, there is a mismatch between cost type and charge type (causation vs. recovery).

  Participants said:

  - If rate design is de-coupled from this discussion, and the focus is on net metering, there may be better clarification and agreement on this and the previous point.

- APS sees rate design and net metering as intertwined; it's hard to ignore the rate question.
- Suggest striking the phrase, "residential and commercial rate categories" to reach agreement.
    - Participants appeared to agree with this suggestion.

Evaluating the Benefits and Costs of Net Energy Metering in California
Tom Beach, Crossborder Energy
Slides 13 - 36

Mr. Beach said that net energy metering (NEM) is a billing arrangement; 43 states have a version of it. Analyzing the effects on non-participating customers is complicated. He pointed out that people would have the right to install solar on homes with or without net metering, which is the price of exports to the grid. There is a question, however, as to whether the retail rate that credit customers get equals the value of the power to the utility. In most cases, the exported power is a minority of what's generated. Mr. Beach thinks it makes sense to use similar cost/benefit (C/B) analyses for energy efficiency (EE) and DE, as it is important to use the same test for all demand-side resources. He also noted it is also important to distinguish between distributed generation and net metering.

Mr. Beach reviewed major costs and benefits in demand-side analysis. The Ratepayer Impact Model (RIM), which reflects the utility's lost revenues, is the one that reflects the net metering issue. States weight these tests differently. He described how the NEM cost/benefit analysis was done and addressed misconceptions about this. He noted that the real issue is determining the value of the NEM exports. The main question of this study is, "Is the retail rate of self-generation equal to the retail value of the energy?"

Qs & As: [Answers provided by speaker]

- Is the underlying assumption that all these costs would be avoided costs?

No, there could be other costs, such as integration costs and incremental costs.

- Regarding avoided costs assumed as a benefit of NEM, does the analysis consider capacity value of the resource and how that affects avoided costs?

Yes.

Participant Comments and Observations

- Request Mr. Beach provide a reference to the California Standard Practice Manual for Net Metering.

- APS assumes that all customers pay the same for power. Under the current rate design, is there a mismatch? If energy use (meter runs forward) and the credit received for sales back to the grid (meter runs backward) are the same, then "we're square."

Mr. Beach discussed the need for a new study, noting that while this issue is important, NEM only represents 0.4% of the revenues of California's three large utilities. The last study was done in 2009 when PG&E rates were the very highest. Since then, rate design changes have reduced Tier 3 and 2 rates. Now, forecasts for rate escalation are lower. Reduced resource portfolio standards (RPS) requirements are part of the avoided cost model. NEM exports to the grid are 100% renewable, replacing generated power that is 20-33% renewable. Utilities don't get credit for this toward the RPS goal, so this additional increment of renewable generation can be treated as an avoided cost.

Participants had several questions and comments on the study's avoided cost model assumptions.

Qs & As: [Answers provided by speaker]

- Where does the model take into account the need to have energy that can ramp up (on cloudy days), and if there is a need to have more reserves in the system?

CA has not yet adopted integration costs. No one has yet to identify any significant integration costs. They aren't included.

- **Are there any examples of studies that take into account these costs, particularly for the residential sector?**

One example is the Colorado wind integration study.

- Arizona still has 40% coal generation; creating creates $5 in damages for every $1 of coal generation.

CA has no coal on the margin, so the marginal resource is a combined cycle plant. Arizona may need to use different assumptions for a similar model. There is an allowance for losses and for GHG costs (in the $10-13 range in 2013).

- Is this approach looking at avoiding equipment, or the duty cycle of equipment?

Yes; if demand is lower, a utility will make fewer investments in transmission and distribution (T&D) over the long term. CA has a standard regression methodology to calculate this.

- Would this require utilities to change components like wire size, etc., to account for these small changes?

Not necessarily; the methodology doesn't require drilling down that deep. A utility can serve more customers from each facility or with each circuit, so saves money in capital investments.

- If the standard [RPS] is met, does DE continue to have value?

Yes, DE exports aren't counted in the CA RPS. In CA, RPS standards will probably continue to increase. I expect renewable generation in California will exceed 33%; the CPUC is planning to go to 40 %. In my view, DE beyond 33 % penetration has value to the ratepayer and should be considered in the analysis.

- Because of the intermittency of rooftop solar, there will be periods where residences take capacity from T&D, so can you really count this as an avoided cost?

At the transmission level, costs and benefits can only be meaningful if you aggregate them across a system. When you get to the individual circuit, you may lose some of these benefits and may incur some distribution system costs.

- Regarding ancillary services, when APS does resource planning, the utility takes into account intermittency and volatility in the resource profile (e.g. monsoonal effect on solar production at a system level). How is the intermittent value of solar at the system level accounted for in this study? Are integration costs included?

This is an hourly analysis and uses hourly PV data. It has fluctuation in solar output embedded in it, for instance when the fog rolls in. No it doesn't have integration costs because California hasn't adopted values for integration.

- In comparing avoided costs for baseload and solar PV profiles (slide 25), what baseload does this represent?

Equal weighting of avoided cost for every hour of the year at 100% capacity resource.

- In terms of avoided RPS, does the California market have a significant difference between RPS and natural gas?

Yes, about 4.5 cents per kilowatt hour.

- Do capacity benefits of solar resources continue to extend out over time, i.e., would they be the same as now/increase/decrease? Or is this more of a short-term analysis?

In terms of the capacity benefits changing over time, the model doesn't incorporate that time sensitivity now. The model does have a resource balance concept that measures the current year.

- How would results change if the model considered energy production that's serving site load?

We haven't done that analysis, but could speculate that serving onsite load in the morning could be less valuable than higher afternoon costs.

- Where is California headed on block rates?

California had steeply inclining block rates, but the CA Public Utilities Commission is moving away from that and toward time-of-use pricing; this is a slow process of rate redesign. CPUC has statutory constraints on what it can do on residential rate design. There is a trend towards reducing upper-tier rates. Lowest two tiers can only be increased 3 to 5% per year.

- Are there restrictions on basic demand charges in CA?

Yes. Unsurprisingly, consumer groups are opposed to [additional] charges on customers, so it's a difficult practice to implement.

Participant Comments and Observations

- A Florida study shows that there is a correlation between cloudy weather and [increased] demand, because when solar stops generating it also gets cooler.
- While there may be a correlation, in AZ this takes hours to occur because it takes time for residences to cool down.

Mr. Beach described the study approach of dividing 10,000 customers into those using NEM and those who don't (reference case), and comparing annual utility bills. If the reference bill is smaller than the NEM bill, then NEM is a net benefit to other customers. If the reference bill is larger, then NEM is a net cost to other customers. If the bills are equal, other customers are "indifferent." In general, smaller PV systems on larger customers impose NEM costs on others, and larger systems represent a benefit. The study showed that commercial and industrial (C&I) customers produced more benefits than residential customers, across the investor-owned utility market, because they export in the afternoon at higher use times. More benefits in both the residential and C&I markets were realized for the Southern California utilities than for PG&E. Mr. Beach suggested that an idea might be to consider rate modifications that reflect reducing demand charges.

Qs & As: [Speaker provided answers]

- Is there any overarching Arizona Corporation Commission model that can be used in Arizona, rather than criticizing a California model? For example, is there an Arizona-specific cost avoidance model that can be used as a template for all utilities?

No – there will probably never be one model.

- Does California have an avoided cost rate?

[CA has] a statewide model for avoided costs that includes certain assumptions that may not be the same [in AZ].

- Did the model evaluate demand reduction in different customer classes?

Not specifically. It does calculate how customer demand is reduced on an hourly basis by using PV, but [the model] can't break it down by [customer] class.

- Does the model include a hedge cost value?

Gas costs are based on the forward market in California.

Participant Comments and Observations

- It is difficult to reconcile APS' concerns about integration costs of solar [because of its intermittency]; APS doesn't know how to reconcile that with this study's approach.
- The R.W. Beck study mainly looked at savings that could be achieved in T&D, which were quite small compared to generation.
- Suggest looking at the spot price on the Palo Verde rate exchange might reflect true real-time costs (in 15-minute increments). Some of these are much higher than people realize, which shows the benefit of renewable generation.

Fundamentals of Resource Planning and Distributed Energy
Bob Davis, nFront Consulting
Slides 37 – 69

Mr. Davis presented an overview of how generation utilities go about calculating costs for distributed energy. Some utilities implement programs that help customers reduce loads, often in response to regulations, and these are addressed within the context of the utility's integrated resource planning (IRP) programs. APS, for example, has adopted renewable energy and energy efficiency targets, including those for DE (slide 40). Three different tests are used to determine the cost-effectiveness of these programs. This approach is designed to specifically address solar DE and its potential impacts on generation planning, system losses, avoided marginal and generation capacity costs, and the resulting need for capacity additions, considering that there are several different models available for doing this.

Mr. Davis noted that avoided costs occur because solar generation reduces load during much of the day, reduces peak demand, and may delay the need for future resources; however, he observed that these deferred resources may be more efficient than the DE resources. In conducting these analyses, Mr. Davis suggested that solar capacity should be compared against a similar resource like combustion turbine (CT) with a similar capacity value. A major conclusion of this analysis is that solar generation contributions can shift the peak under certain circumstances.

In resource planning considerations, he noted that dependable capacity diminishes with increasing solar DE penetration. For capacity value, APS uses 2 to 5% inflation in its calculations. Using this assumption, about $200/kW per year can be avoided in fixed cost. He showed that as the utility adds more solar resources into the mix, it creates a less efficient dispatch operation. Under these assumptions, the first avoided unit for APS is in 2017. Any solar generation installed before that time is not avoiding any capacity costs. APS's generation expansion plan assumes 100 MW/yr of CT generation, so if solar DE can generate 100 MW/yr, one CT unit can be avoided. This is an avoided cost.

Qs & As:

- What does emission cost mean?

CO_2 only. This study assumes that carbon legislation is adopted, with an assumed price of carbon.

- Regarding the process of identifying future generating resources that can be avoided by solar DE, there is a problem with evaluating incremental benefits v. full benefits. The Beck study only looked at blocks of solar DE. This skews forecasting by the large size of blocks. Suggest considering other load-side resources like EE and DR factors. For example, a block of solar may be 330 MW; if the need is 400 MW, the utility concludes that solar isn't enough, while in reality an aggregate of 300 MW of DE, plus 100 MW of EE plus 100 MW of DR may more than meet this need. There's no need to force these these smaller, short lead time resources into a "lumpy" pattern to match a large resource.

In the Beck study and in the 2013 update, APS is looking at 100 MW and would defer short-term purchases with DE, not large blocks.

- In determining capacity needs, why does the analysis shows the utility purchasing power in excess of demand for the period through 2016?

This reflects previously-purchased power based on [earlier] higher demand forecasts.]These obligations were made] before the recession, and the resulting lower demand forecasts; [Despite the forecast update, APS still has the purchase obligations.

- Among the model alternatives for evaluating capacity additions, is there a preferred one?

There is no industry preferred approach; it's location-specific.

- Will the PROMOD tool be used? Assuming confidential data can't be provided to stakeholders, can benchmarked resources like Palo Verde market prices be provided, to provide confidence that the model is representative of the WECC markets?

Yes, PROMOD is the standard industry tool. Yes, PROMOD is benchmarked internally by comparing to the internal rigorous monthly budget process. These include comparisons against actual fuel and purchase costs. It's important to keep in mind that a pure market price forecast may not include inefficiencies of small increments of generation such as solar DE. These inefficiencies can artificially drive down the value of avoided energy (backing off a coal plant when solar DE ramps up instead of a combined cycle unit because of the need to keep the CCT plant online to meet a peak later in the day). As these DE generation sources increase, they might become relatively significant.

- If there's a resource that's not being used, at what point does the utility determine that resource doesn't have capacity value anymore?

A system can have about 15% of capacity that's never used at any time. Over and above that, the utility would probably want to retire the resource, if it has no operational value or any future need to avoid incurring fixed charges on that asset.

- Capacity value is assigned to resources that actually get used, so peaking solar, for example, should be assigned resource value.

Where load grows over time, as with APS, the utility will always need to add capacity. Any load-side resource has value. If load is not growing and the utility theoretically has no future need for resources, additional resources such as DE, maybe the output of this resource or other resources could be sold and then there would be value. If there's absolutely no use for the resource, then it would have no value.

Participants discussed the lost fixed cost recovery mechanism related to new developments, and whether DE-generating residential subdivisions can offset or replace the cost of providing power to new nearby subdivisions. Some participants assert that in these circumstances, the only new cost to the utility would be local distribution, so existing developments shouldn't be burdened with lost costs, i.e., that solar shouldn't be penalized with the LFCR.

APS staff noted that the utility still incurs a generation cost for the capacity that must be available to serve 100 % of the load some of the time. APS also explained that the utility still must provide the wires and pad-mounted transformers within the new subdivision and those customers will pay for this infrastructure in their rates. APS reminded participants that the question is which costs and how much are avoided by DE and which costs are stranded and thus not being recovered. APS noted that the LFCR does not include any generation costs, only distribution and transmission costs. It is an agreed-upon cents/kWh price that is used between rate cases.

- Will the capacity value of solar installed today be reduced over time if penetration targets aren't met? If there is high penetration of solar, there's no doubt that the peak will shift, and this does not imply that solar today has no value.

No. APS's approach does not penalize solar. In fact, increasing solar contribution to peak use can save a number of megawatts.

- If a utility builds lumpy units, it ultimately avoids the need for capacity in the future.

APS tries to balance out the lumpiness of these additions with short-term market purchases. Also, with deferred capacity, the utility needs to identify specifically when the avoided cost would occur.

- The discussion about how APS calculates avoided cost, and the timing of such, is compelling. How is this discussion factored into the APS process moving forward?

APS said that the IRP process is the right one to bring all the portfolio questions together. The difficulty is figuring out the value today versus the value in the future. [APS must determine] the net present value of avoiding resources. If the utility doesn't need them, it can't cost them. For example, APS has escalators built into coal contracts, but can't monetize them today into rates. One thing APS is trying to do is take all the qualitative factors discussed today and evaluate them, to determine how and if they inform future planning efforts.

- How does this methodology compare to the Austin Energy model?

This will be discussed more in future workshops. This is only one component of the Austin Energy model.

- What is the purpose of the dependable capacity adjustment factor? Is it relevant to the earlier residential subdivision discussion?

No. It's specific to generation planning. This example is a proxy and participants should not read too much into this.

- Clarification on conservative adjustment factor: Would load reduction occur from backing off a coal unit, for example?

Yes.

- Does this mean that the utility could avoid future units of similar kind if the solar penetration were high enough?

Not necessarily. The two can't be directly compared.

- Is the forecasted rate of growth of the solar industry greater than the forecast for the total growth?

By meeting a growing portion of load growth with solar, yes.

Participant Comments and Observations

- Suggest a more rigorous way of looking at resource needs would be an ELCC calculation.
- There is a marginal economic benefit of orientation and axis tracking of solar panels.
- Solar DE can also be used to offset generation losses from other units. For example, a CA utility is unexpectedly losing a nuclear unit, and so has a big [capacity] gap to fill. In this instance, having a little extra solar in the utility's system before it's needed can be a good thing, and also provides an opportunity to sell this energy to your neighbor. Participants at this forum had agreed they wouldn't be bothered by the "lumpiness" factor.
- ["Lumpy" capacity additions vs. "less lumpy" purchases including DE] represents a difference between APS and the solar stakeholders in this process.
- Concerning the dependable capacity adjustment factor, this "conservative adjustment factor" of 20% is not justified; for example, it means that DE offsetting a CT unit of 1,000 MW is only given credit for 800 MW.
- A trend is occurring in CA of people moving from the coast to inland where it's warmer, This is one factor in causing the peak to shift.

APS Resource Planning and Distributed Energy
Paul Smith, APS
Slides 70 - 95

Mr. Smith gave an overview of the APS Integrated Resource Plan (IRP) focusing on solar value components. He provided an update on assumptions and said that this discussion addresses some additional value components discussed on the March 14 stakeholder conference call.

Mr. Smith estimated that distributed energy can contribute about 500 MW of dependable capacity to the APS portfolio. APS needs 3,600 MW by 2025, starting in 2017. Solar DE savings can be realized in fuel, purchase power and loss savings, fixed O&M savings, and generation savings. He showed how resources would be used and mixed under various scenarios such as the summer peak day and a typical spring day in the planning horizon of 2025. APS may have, at high penetration of DE, a challenge in dispatching resources in the shoulder months.

Mr. Smith described some of the assumptions for key drivers used in the current update of the 2009 R.W. Beck study. Load forecasts were reduced somewhat due to the slow economy. DE scenarios increased MW contributions substantially over those predicted in 2009. The forward market date used for gas was12/31/12; gas prices are expected to rise through 2025, but are not expected to reach 2009 forecast prices. A price on carbon was modeled as expected in 2019 and would add 0.8 to 1.2 cents per kW hour to avoided energy costs. Fixed O&M costs were updated, as were generation costs. APS forecasts a need for new generation beginning in 2017.

Mr. Smith gave an example of how the APS system load profile would change over time with the addition of solar, starting with an actual peak day profile in 2012, showing that the peak shifts later in the day with additional solar generation.

Qs&As:

- Will you consider Abengoa's storage [when valuing that solar resource]?

Yes, that will be factored in.

- What's driving the diminished return [on solar DE]?

Pushing the peak to later in the day, the less capacity value you have.

- Is it fair to say solar represents a small percent of system peak?

Yes, currently.

Participant Comments and Observations

- Most of these examples relate to high penetration cases in the long-term future. Maybe in the shorter term there will be new technologies, e.g. storage, that can address some of these challenges. Perhaps APS should be forecasting only for short term and focusing on the next 4-5 years, or re-doing these studies in a few years.

Additional Data Considerations

<u>Slides 96 – 104</u>

Mr. Smith discussed APS's responses to several stakeholder comments from the last meeting regarding market price mitigation, solar panel orientation, grid security benefits, fuel hedge value, environmental compliance savings, reliability benefits, and avoided RPS wholesale purchases.

Qs & As:

- On the subject of market price mitigation, if a value is not assigned, that's saying the value is zero, and that's not correct. TEP suggested that any value assigned must include costs allocated back to the consumer.

APS thinks the value is very small, and it is difficlut for APS to address the indirect value of market price reduction.

- Is APS a net buyer or net seller?

APS is a net buyer.

- On the issue of fuel hedge value: Putting solar on one's houses hedges the value, but this does not necessarily hedge the value for the non-participating neighbor.

APS suggested that is a participant point of view. The utility is looking at this from a non-participant point of view. The utility does get fuel hedging value for all customers when buying power. Forward-forecasting, for example, with the price of gas.

- On the subject of environmental compliance savings, APS explained that it quantifies reductions in power plant emissions in the IRP, but doesn't monetize them. Please clarify how these savings are valued.
- *These savings are valued only through a sensitivity case, not in the main case.* If APS has to buy offsets, is that included in the capital cost of the plant?

Yes.

- How are spinning & non-spinning reserve costs treated?

They are estimated in the $2-3/MW range.

- Participants had alignment at the last meeting on the statement: *"Subsidies for all fuel sources should be considered."* Today's agenda included covering subsidies for fossil fuels and nuclear, but it hasn't been mentioned today.
  - ➢ The facilitator apologized and committed to bring this information to the next meeting.
- Participants requested existing data from FERC and other sources be used for the subsidy discussion, rather than EIA data.
  - ➢ APS agreed to research what data sources it has.
- ➢ For the next session, participants requested the ability to change variables in the model for natural gas prices, lumpiness, and solar panel orientation.
- Did APS receive the participant data requests sent in last week?

Yes, but APS hasn't been able to answer them yet.

Participant Comments and Observations

- Regarding southwest/west facing solar arrays, the energy value may be the same but this orientation provides an increased capacity value.
- To fairly evaluate grid security benefits, a system with lots of small DE generators needs to be compared to a system that relies on large generation units.
- What date should be used for natural gas prices when evaluating avoided RPS wholesale purchases? Consider that short-term market prices are volatile, but the long-term market doesn't change that much.
- In future meetings, be clear in addressing the subject of subsidies whether referring to state or federal subsidies. There are implications for state policies, such as in the area of customer-owned versus leased solar systems.

Distributed Energy Costs and Benefit Alignment Discussion

Mr. Gabriel asked participants to refer to the cost and benefit listing distributed today and to provide comments on what's missing. Participants decided that another conference call was not needed to discuss these topics, and said they would review the handout and let Mr. Gabriel know of any additions or concerns. APS noted that it wants to ensure all variables and questions have been addressed.

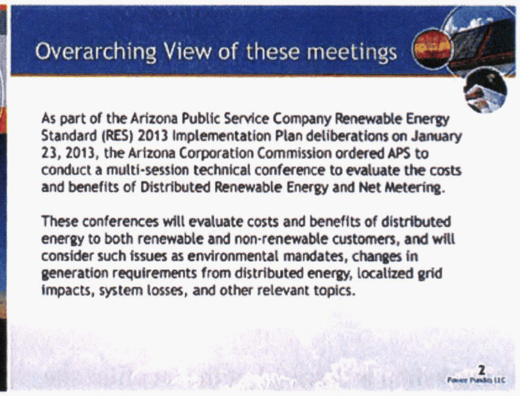
Participant observations and comments:

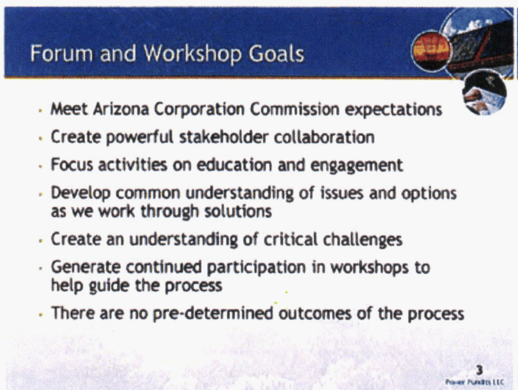
- A benefit is that customers reduce energy use and become more aware. There is a civic component to this issue.
- Where is grid security reflected?
- The planning horizon is a challenge in the face of new technologies.
- ➢ It was agreed that Mr. Gabriel and APS would fill in the Benefit and Cost Categories summary sheet and stakeholders would review it. Tucson Electric volunteered to help with this.

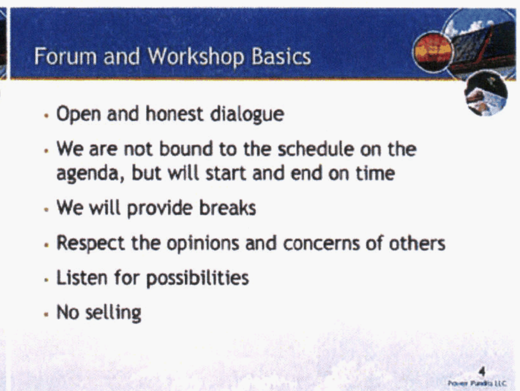
The next workshop is April 11 at the Ocotillo site.

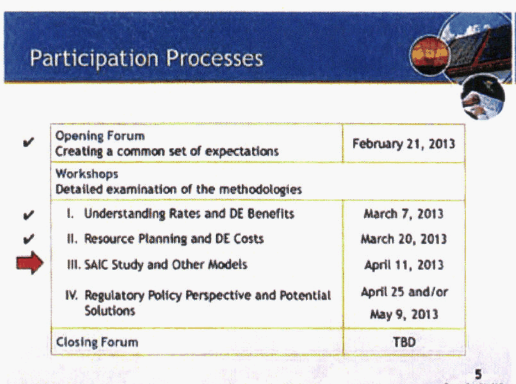
Workshop III (April 11, 2013)

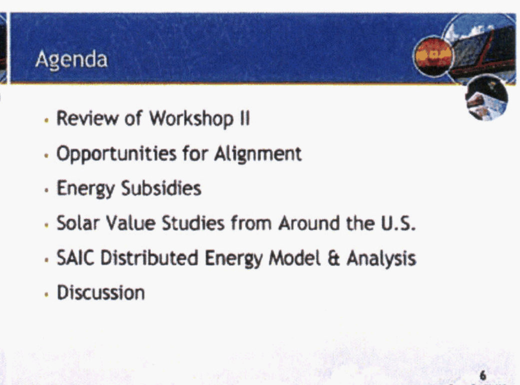
Presentations











Agenda

8:30	**Welcome** Review of Issues, Goals and Questions	**Bob Davis, *nFront Consulting***
9:00	**Opportunities for Alignment**	**Bob Davis, *nFront Consulting***
9:30	**Energy Subsidies**	**Round Table Discussion**
10:00	**Solar Value Studies from Around the U.S.**	**Tom Hoff, *Clean Power Research***
11:00	**Lunch**	
12:15	**SAIC Distributed Energy Model & Analysis** Input and Assumptions Draft Avoided Cost Results Stakeholder Opportunity to Review SAIC Analysis	**Scott Burnham, SAIC**
2:00	**Discussion of the Models Presented**	**Facilitated Group Discussion**
2:30	**Adjourn**	

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Review of Workshop II

- DE has an impact on utility operations and planning
- DE may reduce certain utility costs of generation:
  - Fuel and purchased power
  - Variable operation and maintenance (O&M)
  - Cost of environmental compliance
  - Investments in new generating facilities
  - Fixed O&M for new generating facilities

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Review of Workshop II (cont.)

- DE energy production and capacity should be adjusted for grid losses when computing value
- Dependable capacity credit of DE is a function of its impact on utility reliability and coincidence with utility load shapes
  - Effective load carrying capability (ELCC)
  - Coincidence with the electric system peak
  - Diminishing capacity value with increasing penetration

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Review of Workshop II (cont.)

- Review of California net metering programs and rate structures (Update of a 2009 E3 study performed by Tom Beach, Crossborder Energy)
  - Two of three CA IOUs show no cross-subsidization between residential participating and non-participating customers
  - All three IOUs show no cross-subsidization for C&I customers
  - Greater adoption of TOU rates reduces cross-subsidization

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Moving Forward

- Alignment is a difficult concept for participants
  - Generally statements or observations
  - Alignment on technical modeling issues may prove difficult to achieve
- But it is still useful to identify major technical topics and note views of workshop participants
  - Identify topics that have been addressed by the current analysis or through workshop discussions
  - Note which topics have been addressed to the general satisfaction of all workshop participants
  - Note topics where workshop participants have differing opinions on analytic approach
  - List specific issues affecting different opinions

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Cost & Benefits Matrix

Category	Description
Fuel & Purchased Power	Utility fuel costs for generation and costs for power purchased from others may be reduced by DE
Variable Operations & Maintenance	Utility O&M costs that vary with the amount of energy produced or sold may be reduced by DE
Water Consumption	Utility consumption of water to generate electricity may be reduced by DE
Cost of Environmental Compliance	Utility costs for environmental compliance may be reduced by DE
Fuel Hedging	Utility cost of hedging future uncertain fuel costs may be reduced by DE
Capacity Value (MW)	The amount of capacity that could be avoided or deferred by the installation of DE
Investment in New Utility Capacity	Utility costs of investments in new generating resources or purchased capacity may be avoided or deferred by DE
Fixed Operations & Maintenance	Utility O&M costs associated with an avoided or deferred generating resource that do not vary with the amount of energy produced or sold may be avoided by DE

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Cost & Benefits Matrix

Category	Description
Line Losses	Difference in the amount of electricity generated and that available for use by the consumer. Energy and demand losses that occur on the transmission and distribution systems
Transmission System	Electrical infrastructure used to transmit power from generating resources or other utilities to the utility's local distribution grid. Investments in new transmission infrastructure may be avoided or deferred by DE
Distribution System	Electrical infrastructure used to distribute power from the transmission system to the consumer. Investments in distribution system infrastructure may be avoided or deferred by DE
Ancillary Services	Services necessary to support the reliable operation of the electric system (scheduling & dispatch; reactive power & voltage control; loss compensation; load following; system protection; energy imbalance). Because DE power output is transient, it may increase requirements for some ancillary services, thus increasing utility operating costs.

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Cost & Benefits Matrix

Category	Description
RPS Avoided Costs	Utility costs for purchasing renewable energy to meet ACC requirements that may be avoided by DE
Market Price Mitigation	Utility costs for market purchases may be reduced by DE
PV System Orientation	Southwest orientation may provide more capacity value (more generation when a utility needs it), thus increasing the value of avoided capacity-related costs
Economic Development	Spurring of local businesses or industries may be enhanced by implementation of DE
Grid Security	DE may provide alternative sources of power that can enhance security of the electric system
Health Effects	DE may reduce the use of traditional fossil-fueled generating resources, thus reducing potential adverse health effects
Jobs	DE may create jobs in the distributed energy and solar industries, thus benefiting the local communities
Civic Engagement/Conservation Awareness	DE may raise public awareness in energy conservation and increase participation in other programs and services

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Energy Subsidies

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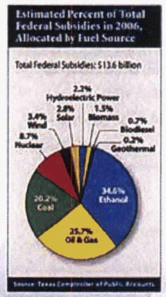
Subsidies and Energy



Good data is difficult to find

- Various sources quote data differently
- State specific data is particularly challenging

Subsidies typically include the following categories

- Direct expenditures
- Tax expenditures
- Research and development (R&D)
- Loans and loan guarantees
- Targeted programs

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Federal Energy Subsidies to the Electric Power Sector - EIA Report

- $11.9B of electricity-related subsidies in 2010
- 29% direct expenditures
  - Wind generation receive 84%
- 28% tax-related subsidies
  - Renewables accounted for 40%
  - A nuclear decommissioning-related tax credit accounted for $0.9B in 2010
- 22% research and development
  - Nuclear accounted for the highest level of R&D expenditures at $1.1B, with renewables and coal each at approximately $0.6B
- Renewables received a large share of federal subsidies relative to their share of electricity production
  - 55% allocation of subsidies in 2010
  - 10% of electricity production in 2010

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Matter of Perspective (2010)

Beneficiary	Direct Expense	Tax Expense	R&D	Federal Electricity Support	Loan Guarantees	Total	Share of Total Subsidies & Support	Share of Electricity Generation
Coal	37	486	575	91	0	1,189	10.0%	44.9%
Natural Gas and petroleum liquids	1	583	15	56	0	654	5.5%	25.0%
Nuclear	0	908	1,169	157	265	2,499	21.0%	19.6%
Renewables:	4,178	1,347	632	133	269	6,560	55.3%	10.3%
Biomass	6	54	55	0	0	114	1.0%	1.4%
Geothermal	115	1	72	0	12	200	1.7%	0.4%
Hydropower	17	17	51	130	0	215	1.8%	6.2%
Solar	409	99	287	0	173	968	8.2%	0%
Wind	3,556	1,178	166	1	85	4,986	42.0%	2.3%
Unallocated Renewables	75	0	0	0	0	75	0.6%	0%
Transmission & Distribution	461	58	222	211	20	971	8.2%	NA
Total	4,677	3,382	2,613	648	555	11,873	100%	100%

Source: Energy Information Administration

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Experiences from Around the U.S.

Tom Hoff, Clean Power Research

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Applying DGValuator to Quantify Value of Solar in APS Service Territory

April 11, 2013

Clean Power Research

Project Objective

- Support AZ stakeholder input by applying DGValuator to quantify value of solar in APS territory
- Benchmark DGValuator using SAIC study results to develop stakeholder confidence in model
- Produce range value for various benefits from which policy makers can assign total value

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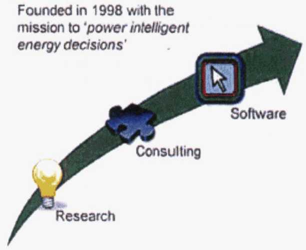
Clean Power Research®

Founded in 1998 with the mission to *'power intelligent energy decisions'*



SOLAR PREDICTION
Most widely used solar resource database

ECONOMIC VALUATION
> 25 million solar estimations performed

PROGRAM OPTIMIZATION
2.75 GW of renewable incentives processed

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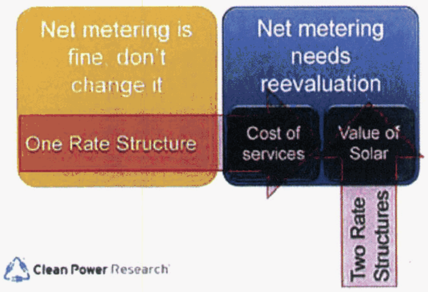
Where Does APS Stakeholder Process Fit in the Net Metering Landscape?



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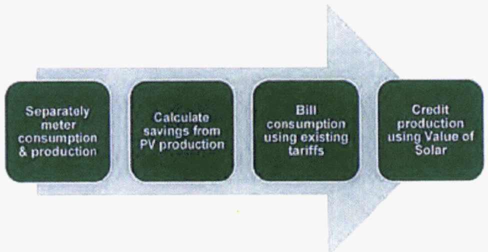
Value of Solar Approach



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Value of Solar to the Utility

Value Component	Basis
Avoided Fuel Cost	Cost of natural gas fuel to operate a gas turbine (CCGT) plant operating on the margin to meet electric loads and T&D losses.
Avoided Plant O&M Cost	Costs associated with operations and maintenance of the CCGT plant.
Avoided Generation Capacity Cost	Capital cost of generation to meet peak load and planning margins.
Avoided T&D Capacity Cost	Cost of money savings resulting from deferring T&D capacity additions.
Avoided Environmental Compliance Cost	Cost to comply with environmental regulations and policy objectives.
Fuel Price Hedge Value	Cost to minimize natural gas fuel price uncertainty.
(Solar Penetration Cost)	Additional cost incurred to accept variable solar generation onto the grid.

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Value of Solar to Ratepayers and Taxpayers

Value Component	Basis
Economic Development Value	Enhanced tax revenues associated with net job creation for solar versus conventional power generation.
Environmental Value	Future cost of mitigating environmental impacts of coal, natural gas, nuclear, and other generation.
Security Enhancement Value	Avoided economic impacts of outages associated due to grid reliability of distributed generation.
Market Price Reduction	Wholesale market costs incurred by all ratepayers associated with a shift in demand.

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Use dgVALUATOR to Perform Value of Solar Analysis

- Enable objective and transparent analysis
- Employ established methodologies
- Embody correlated solar data
- Empower end-users

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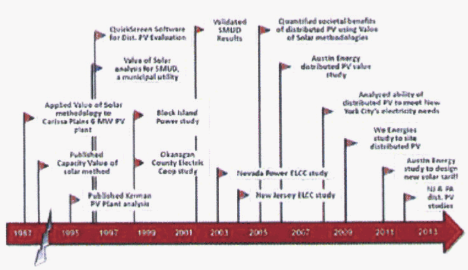
DGValuator History



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Value of Solar to Utility Example at Austin Energy

How does Austin Energy...

- Design a solar tariff representing utility value for customer-side distributed solar?
- Allow utility to collect and recover actual costs for serving customer loads?

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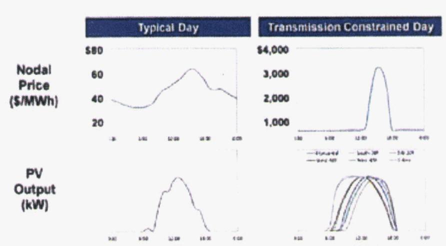
Nodal Price Analysis (Energy Value)



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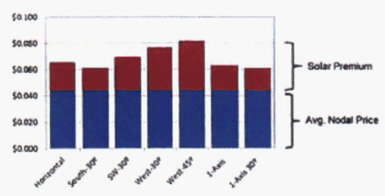
Nodal Price Analysis Results (Energy Value)



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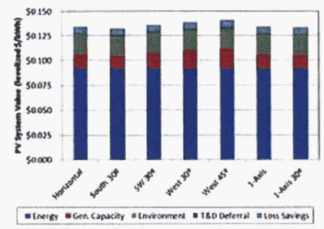
Update Value of Solar Based on Nodal Price Analysis



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Lessons Learned from a VOS Implementation

Difficulty	Solution
Transition from net metering to VOS occurred simultaneously with major rate case	Separate net metering issue from general rate case
Mandatory migration to VOS made customers suspicious that they would be worse off	Be transparent by providing customers with online tools so they can perform their own analysis Transition gradually
Solar advocates were suspicious and were not convinced that they were better off with VOS	Be as transparent as possible with the analysis Provide the opportunity for extensive stakeholder input
Transition occurred in parallel with conversion to new billing systems	Run old and new billing systems in parallel
VOS credits were applied to other services on the customer's bill (e.g., garbage)	Clearly community how credits will be applied Consider rolling over kWh, not $
Whoever does analysis must understand the resource (e.g. some used PVWatts to perform time-correlated analysis)	Be transparent with methodologies and provide tools
Lingering issue about updating annually	Consider locking customers into long-term VOS and putting subsequent customers on new VOS rate
Question assumption about south-30 degree system	Perform analysis for actual fleet of PV systems installed

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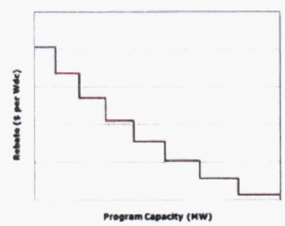
Solar Rate Required Redesign of PV Rebate



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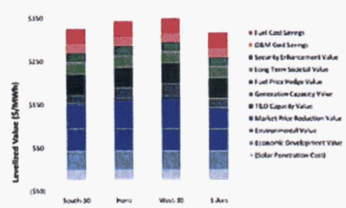
Full Value of Solar (Utility, Ratepayers &Taxpayers) PA and NJ Study (for MSEIA)



Note: Results were developed for multiple locations. Figure presents results for Philadelphia, PA

http://mseia.net/site/wp-content/uploads/2012/05/MSEIA-Final-Benefits-of-Solar-Report-2012-11-01.pdf

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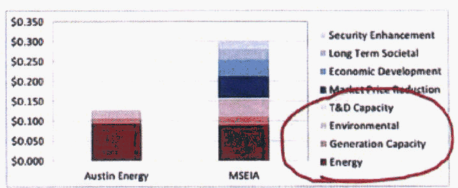
How Do Austin Energy and MSEIA Results Compare?



(1) Proportionately allocate Loss Savings across categories for Austin Energy.
(2) Group Fuel Cost Savings, O&M Cost Savings, and Fuel Price Hedge into Energy for MSEIA.
(3) Allocate Solar Penetration Cost to utility benefits for MSEIA.
(4) Location is Philadelphia for MSEIA.

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Methodology Description

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Value of Solar to the Utility

Value Component	Basis
Avoided Fuel Cost	Cost of natural gas fuel to operate a gas turbine (CCGT) plant operating on the margin to meet electric loads and T&D losses.
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Avoided Environmental Compliance Cost	Cost to comply with environmental regulations and policy objectives.
Fuel Price Hedge Value	Cost to minimize natural gas fuel price uncertainty.
(Solar Penetration Cost)	Additional cost incurred to accept variable solar generation onto the grid.

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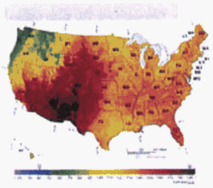
PV Power Simulation
(Using Time- and Location Correlated Solar Data)

Irradiance data
- Historical satellite-derived time-series data from 1998 through latest hour
- Forecasts up to 7-days in advance by combining cloud motion vector and NWP approaches

Analytical tools
- PV system modeling (FleetView)
- PV benchmarking (DataCheck)
- PV fleet variability



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Loss Savings

- Distributed resources reduce system losses by producing power in the same location where it is used
- Loss savings increase the value of other benefits across generation, transmission, and distribution systems
- Correct loss savings depend upon the benefit category
- Loss savings are calculated on the margin

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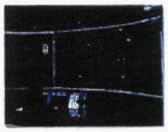
Energy Value

- Definition
  - Benefit from distributed PV generation's offset of wholesale energy purchases
- Methodology
  - Energy value equals PV output plus loss savings times marginal energy cost
  - Marginal energy costs are based on fuel and O&M costs of generator operating on the margin (CCGT)



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Generation Capacity Value

- Definition
  - Benefit from added capacity provided to the generation system by distributed PV
- Methodology
  - Generation capacity value equals generation capacity cost times PV's effective load carrying capability (ELCC), taking into account loss savings
  - Generation capacity cost is based on capital cost of CCGT

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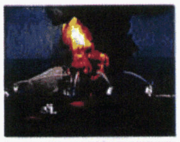
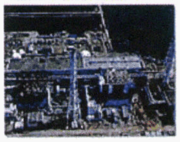
Fuel Price Hedge Value

- Definition
  - Benefit that distributed PV generation has no fuel price uncertainty
- Methodology
  - Fuel price hedge value is calculated by determining how much it would cost to minimize the fuel price uncertainty associated with natural gas generation





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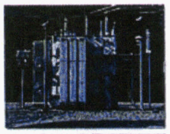
T&D Capacity Value

- Definition
  - Benefit that distributed PV generation provides in reducing the burden on the T&D system and thus delaying the need for capital investments in the T&D system
- Methodology
  - T&D capacity value equals the expected long-term T&D system capacity upgrade cost, divided by load growth, times financial term, times a factor that represents match between PV system output (adjusted for losses) and T&D system load



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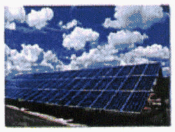
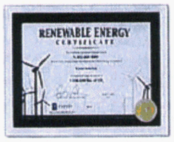
Environmental Value

- Definition
  - Benefit that the environmental footprint of PV is considerably smaller than that of fossil-based generation
- Methodology
  - Environmental value equals PV output times REC price





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Value of Solar to Ratepayers and Taxpayers

Value Component	Basis
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Security Enhancement Value	Avoided economic impacts of outages associated due to grid reliability of distributed generation.
Market Price Reduction	Wholesale market costs incurred by all ratepayers associated with a shift in demand.

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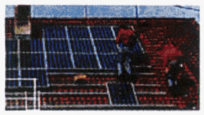
Economic Development Value

- Definition
  - Benefit that PV creates more local jobs than conventional generation and thus increases tax revenue
- Methodology
  - Quantify the net increase in jobs and the corresponding increase in tax revenue



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Environmental Value (Non-Utility Portion)

- Definition
  - Benefit that PV has added environmental benefits not captured by utility cost savings
- Methodology
  - Environmental value equals full environmental value minus utility portion

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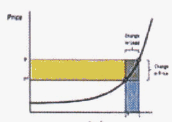
Indirect or Market Price Reduction

- Definition
  - Benefit that occurs when power prices are reduced in addition to load quantity (typically occurs a in a market structured where the last unit of generation sets the clearing price)
- Methodology
  - Multiply change in price times remaining load



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Project Objective

- Support AZ stakeholder input by applying DGValuator to quantify value of solar in APS territory
- Benchmark DGValuator using SAIC study results to develop stakeholder confidence in model
- Produce range value for various benefits from which policy makers can assign total value

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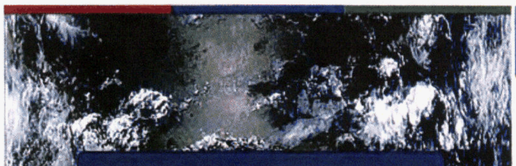

Thank You

Clean Power Research

Questions? Contact Tom Hoff

www.cleanpower.com

Participation Processes

✔	Opening Forum Creating a common set of expectations	February 21, 2013
	Workshops Detailed examination of the methodologies	
✔	I. Understanding Rates and DE Benefits	March 7, 2013
✔	II. Resource Planning and DE Costs	March 20, 2013
➡	III. SAIC Study and Other Models	April 11, 2013
	IV. Regulatory Policy Perspective and Potential Solutions	April 25 and/or May 9, 2013
	Closing Forum	TBD

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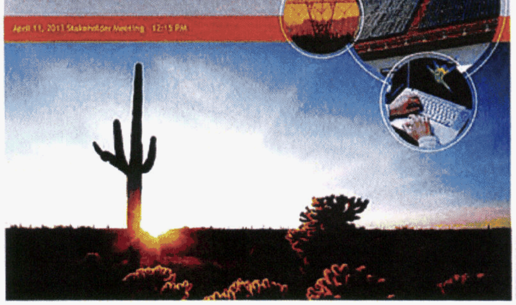
SOLAR FUTURE ARIZONA

2013 Solar PV Value Update - SAIC Report Results and Methodology

April 11, 2013 Stakeholder Meeting 12:15 PM



Introduction to 2013 Report

- Assesses value of incremental solar PV
  - <1,000 systems (2009)
  - ~14,000 systems (2012)
- Leverages the 2009 Study data, methodologies, and assumptions
  - Distribution
  - Transmission
  - Generation
- Target Years: 2015, 2020, and 2025
- Focuses on actual measured performance / observations

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Updated Study Assumptions - Key Drivers

- Increased solar PV penetration projections
  - Increases avoided energy / dependable capacity
- Lower natural gas price forecast
  - Lowers production / purchase power costs
- Lower cost projections for CO_2 emissions
  - Reduces projected cost of traditional generation
- Lower load forecast
  - Reduces avoided energy and deferred capacity costs

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Solar PV Characterization

- Number of installed systems increased
- Average system size increased
  - Combined residential / commercial systems for deployment projections

	2009 Study	2013 Update
Residential		
• # Installations	• >1,000	• 14,000
• Avg. System Capacity	• 5.6 kW_{DC}	• 7 kW_{DC}
Commercial		
• # Installations	• 38	• 700
• Avg. System Capacity	• 105 kW_{DC}	• Range - 349 kW_{DC} (Large) - 74 kW_{DC} (small)

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Solar PV Characterization (cont'd)

- APS modeled solar PV energy projections
  - 30 Year Typical Metrological Year data
  - Characteristics from installed systems
  - PV Watts software
- Consistent with range of modeled output results in 2009 Study
  - Residential: 1,650 kWh / KW_{DC}
  - Commercial: 1,500 kWh / KW_{DC}

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Solar PV Penetration Scenarios

- Expected Penetration Case
  - Approximately 2 times solar PV mandated by 2025
- High Penetration Scenario
  - Approximately 4 times solar PV mandated by 2025
- Low Penetration Scenario
  - Compliance scenario to meet mandate by 2025

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Solar PV Deployment Assumptions

Average system energy losses: 7%

Solar PV Energy Projections

	Incremental Solar PV Production (MWh)	Annual Energy Losses (MWh)	Incremental Total Solar PV Projections (MWh)
Expected Penetration Case			
2015	402,387	28,167	430,554
2020	1,305,771	91,404	1,397,175
2025	2,562,491	179,374	2,741,866
High Penetration Scenario			
2015	402,387	28,167	430,554
2020	1,665,825	116,608	1,782,433
2025	5,049,975	353,498	5,403,473
Low Penetration Scenario			
2015	271,151	18,981	290,132
2020	561,894	39,333	601,226
2025	1,216,976	85,188	1,302,165

Peak Hour Demand Losses: 11.7%

Avoided losses - included in the solar PV dependable capacity to calculate the total peak load reduction and associated value.

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Value Assessment Methodology

- Distribution
  - Deferment in distribution capital expenditures
  - Extension in service life (no value)
  - Reduction in equipment sizing (no value)
- Sub-Transmission deferment
- Transmission deferment
  - Load related projects
  - Generation related projects
- Generation
  - Avoided energy
  - Deferred capacity
- Total estimated annual value - ($/MWh)
  - Nominal (Target Year dollars)
  - Present Value (2013 dollars)

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Distribution System Capital Deferral

- Are projected solar PV installations on any distribution feeders sufficient to defer planned upgrades due to reduced peak load from solar PV?
  - 2009 Study identified distribution capital deferral only for "targeted" scenario
- Feeder peak load compared to rated capacity, with and without solar PV, based on annual hourly residential load profile
  - Projects proposed if feeder load exceeds 90% of rated capacity
  - Potential project deferral if solar PV reduces feeder load to <90%

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Distribution System Capital Savings

Distribution Feeder Screening Analysis	
Total # Feeders	1,351
Total # Feeders w/ Solar PV Installed	872
# Feeders w/ at least 10% or more of installed PV capacity relative to the total peak load	63
Feeders w/ peak PV production that reduced load below 90 percent of the rated capacity	5
Growth Scenario - Feeders with peak PV production below 90 percent of rated capacity	9
Potential Delay of Upgrades	5-10 years

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Sub-Transmission System Capital Deferral

- APS identified projects potentially postponed by solar PV
- Projected solar PV on feeders determined regional impacts
- Postponement past target year results in annual value
- Levelized carrying charge: 11.05 %

69 kV Transmission Capital Improvement Potential Capex Deferral

Project Code	Region	Dependable MW Required for Deferral	In Service Date	Capex Investments (2013 $000)	Deferral Period
Project A	Metro Central	30 MW	2021	$14,065	3 years
Project B	Rural Western	20 MW	2019	$7,980	3 years
Project C	Metro Western	15 MW	2017	$560	3 years
Project D	Metro Western	20 MW	2017	$1,600	3 years
Project E	Northwest	10 MW	2021	$1,200	5 years
Project F	Northwest	20 MW	2021	$3,200	5 years
Project G	Northwest	20 MW	2017	$900	5 years

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Sub-Transmission Capital Deferrals

Expected Penetration Case

Region	MW Required	Need Date	2013 Installed Cost ($000)	Postponed Date	2020 Regional Peak Solar (MW)	2025 Regional Peak Solar (MW)	2025 Associated Annual Value ($000)
Rural Western	20 MW	2019	$7,980	2022	2	7	0
Northwest	10 MW	2021	$1,200	2026	3	12	$133
Northwest	20 MW	2021	$3,200	2026	3	12	0
Northwest	20 MW	2017	$900	2022	3	12	0

High Penetration Scenario

Region	MW Required	Need Date	2013 Installed Cost ($000)	Postponed Date	2020 Regional Peak Solar (MW)	2025 Regional Peak Solar (MW)	2025 Associated Annual Value ($000)
Rural Western	20 MW	2019	$7,980	2022	8	18	0
Northwest	10 MW	2021	$1,200	2026	13	30	$133
Northwest	20 MW	2021	$3,200	2026	13	30	$354
Northwest	20 MW	2017	$900	2022	13	30	0

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Load Related Transmission System Capital Deferral

- Compared APS projected hourly loads (w/ and w/o solar PV installed)
- Estimated system peaks at Expected and High penetration levels
- Determined peak reductions (dependable capacity) for transmission deferrals
- Reduced peaks were compared to determine if Ten Year Transmission Plan projects could be delayed past the target years
- Analysis resulted in zero load-related transmission capacity deferrals

Reduced System Peak Compared to Target Load Levels (MW)

	Target Year 2020	Closest Reference Case Load Level	Target Year 2025	Closest Reference Case Load Level
Projected Peak Loads (no solar PV reference case)	8,019	N/A	9,307	N/A
Expected Penetration Case	7,740	2019	8,881	2024
High Penetration Scenario	7,705	2019	8,665	2023
Peak Load Reduction				
Expected Penetration Case	279		427	
High Penetration Scenario	314		642	

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Generation Related Transmission System Capital Deferral

- Assumed ~$21 million per CT ($2013)
- Levelized carrying charge: 11.05 %

Generation Related Transmission System Capital Deferral

	Cumulative Installed Capacity Cost Reductions ($000 Nominal)	Associated Annual Value ($000 Nominal)	Present Value ($000)
Expected Penetration Case			
2015	$0	$0	$0
2020	$46,968	$5,190	$3,189
2025	$73,883	$8,164	$3,542
High Penetration Scenario			
2015	$0	$0	$0
2020	$46,968	$5,190	$3,189
2025	$73,210	$8,089	$3,510
Low Penetration Scenario			
2015	$0	$0	$0
2020	$23,194	$2,562	$1,574
2025	$49,436	$5,462	$2,370

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Generation Value Components

- Avoided Energy
  - Fuel, variable O&M, emissions, purchased power
- Deferred Capacity
  - Installed CT capital costs, gas transportation, fixed O&M

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Avoided Energy Assumptions

Projected Natural Gas Prices and CO_2 Emission Costs

2013 Report	2015	2020	2025
Delivered Natural Gas Price ($/MMBtu)	4.48	5.82	7.66
CO_2 Allowance Price ($/ton)	0	15.72	22.56
2009 Study			
2009 Delivered Natural Gas Price ($/MMBtu)	8.44	N/A	9.61
2009 CO_2 Allowance Price ($/ton)	20.94	N/A	32.30

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Avoided Energy Value
APS PROMOD Modeling

	Incremental Solar PV (w/Losses) (MWh)	Nominal Value ($000)	Present Value ($000)
Expected Penetration Case			
2015	430,554	$12,988	$11,301
2020	1,397,175	$61,817	$37,984
2025	2,741,866	$162,519	$70,522
High Penetration Scenario			
2015	430,554	$12,988	$11,301
2020	1,782,433	$78,077	$47,975
2025	5,403,473	$290,257	$125,951
Low Penetration Scenario			
2015	290,132	$8,838	$7,690
2020	601,226	$28,792	$17,691
2025	1,302,165	$88,470	$38,390

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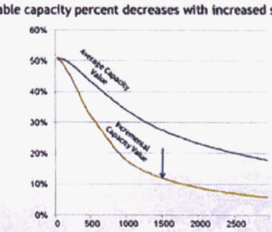
PV Generation Dependable Capacity

- PV Solar peak of12 noon/1:00 PM vs. APS System Peak of 5:00 PM
- Loss of Load Expectation (LOLE)- statistical analysis of historical load / solar production (from 2009 Study)
- Dependable capacity percent decreases with increased solar PV (non-linear)



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PV Generation
Diminishing Dependable Capacity

Solar PV Incremental Dependable Capacity			
Expected Penetration Case	2015	2020	2025
Nameplate PV Capacity (MW_{ac}) w/ losses	242	768	1,504
Avg. PV Capacity Value (System)	45.9%	30.5%	21.0%
Dependable Capacity (MW)	111	235	316
Incremental Capacity Value of the Next 50 MW	34.1%	11.4%	5.3%

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Generation Capacity Deferrals

- Net difference between solar PV and no-solar PV (base)
- Assumed 102 MW CT

Avoided Capacity Resources			
	2020 Avoided CT Resources	2025 Avoided CT Resources	2025 Avoided Wholesale Purchases (MW)
Expected Penetration Case	2 CTs (204 MW)	3 CTs (306 MW)	-10
High Penetration Scenario	2 CTs (204 MW)	3 CTs (306 MW)	45
Low Penetration Scenario	1 CT (102 MW)	2 CTs (204 MW)	29

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Generation Capacity Assumptions

Capital / Fixed Operating Costs and Power Purchases ($2013)	
Combustion Turbine Installed Cost ($/kW)	$1,136
Combustion Turbine Fixed O&M ($/kW-year)	$5.46
Gas Pipeline Reservation Fee ($/Decatherm-month)	$27.14
Wholesale Power Purchases ($/kW-yr)	$102.40

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Generation Capital Deferrals

	Cumulative Installed Capacity Cost Reductions ($000)	Nominal Value ($000)	Present Value ($000)
Expected Penetration Case			
2015	$0	$0	$0
2020	$258,917	$28,926	$17,774
2025	$407,286	$45,502	$19,744
High Penetration Scenario			
2015	$0	$0	$0
2020	$258,917	$28,926	$17,774
2025	$403,579	$45,087	$19,565
Low Penetration Scenario			
2015	$0	$0	$0
2020	$127,860	$14,284	$8,777
2025	$272,523	$30,446	$13,211

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Total Solar PV Value

	Incremental MWh (w/ losses)	Total Nominal Value ($000)	Nominal Unit Value ($/MWh)
Expected Penetration Case			
2015	430,554	$ 12,988	$30.17
2020	1,397,175	$ 100,739	$72.10
2025	2,741,866	$ 224,248	$81.79
High Penetration Scenario			
2015	430,554	$ 12,988	$30.17
2020	1,782,433	$ 116,866	$65.57
2025	5,403,473	$ 351,851	$65.12
Low Penetration Scenario			
2015	290,132	$ 8,838	$30.46
2020	601,806	$ 47,976	$79.72
2025	1,302,165	$ 129,666	$99.58

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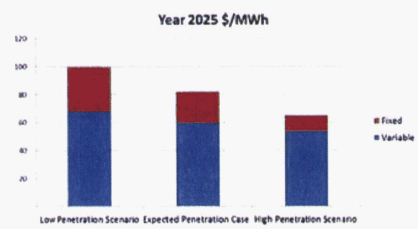
Total Solar PV Value - Fixed & Variable



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Total Solar PV Value

- Discounted at APS WACC (7.21%)

	Incremental MWh (w/ losses)	Total Present Value ($000)	Present Value ($/MWh)
Expected Penetration Case			
2015	430,554	$11,301	$26.25
2020	1,397,175	$61,900	$44.30
2025	2,741,866	$97,308	$35.49
High Penetration Scenario			
2015	430,554	$11,301	$26.25
2020	1,782,433	$71,810	$40.29
2025	5,403,473	$152,679	$28.26
Low Penetration Scenario			
2015	290,132	$7,690	$26.51
2020	601,806	$29,479	$48.98
2025	1,302,165	$56,266	$43.21

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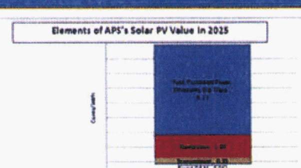
Summary of 2025 Solar PV Value
By Functional Element (Nominal and Present Value)



	2025	2025 Present Value
Distribution	0.00	0.00
Fixed O&M	0.08	0.04
Transmission	0.50	0.13
Generation	1.44	0.72
Fuel, Purchased Power, Emissions, Gas Trans	6.13	2.64
Total	8.178	3.55

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2009 Solar DE vs. 2013 Solar PV Value

2013 Report Comparison to 2009 Study ($ Nominal)			
2025 Target Year Case	Total Solar DE / PV Savings ($000)	Estimated MWh Savings	Estimated Unit Savings ($/MWh)
2009 Low DE Penetration Case	$18,679	176,009	$106.12
2009 Medium DE Penetration Case	$208,924	1,788,610	$116.81
2009 High DE Penetration Case	$382,307	3,862,585	$98.98
2013 Low PV Penetration Scenario	$129,666	1,302,165	$99.58
2013 Expected PV Penetration Case	$224,248	2,741,866	$81.79
2013 High PV Penetration Scenario	$351,851	5,403,473	$65.12

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Conclusions

- Change in values from 2009 Study
  - Reduction in fuel price / CO2 price
  - Reduction in losses
  - Increase in solar PV penetration
- No capacity value savings in short term
  - Resource planning needs are long-term / Energy savings exist
  - No load-related transmission project deferral
- Increased penetration = increased savings
  - Relationship not linear - dependable capacity
- Unit savings ($/MWh) inverse of penetration levels
  - Rate of changes in MWh <> changes in dollars
- Value from Solar PV to APS system exists

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Next Steps

- New items provided by stakeholders are being posted to www.solarfuturearizona.com as they become available
- Over 24 studies on distributed energy, net metering, and solar energy from around the U.S. have been posted for consideration by workshop participants (12 new studies were posted this week)
- Responses to the stakeholders' data requests have been posted
- Meeting notes from Workshop II and the March 14th conference call will be posted this week
- Today's presentation has been posted

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Questions

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Meeting Notes

POWER PUNDITS LLC.

Decision and Process Advisement in Energy and Water

TO: APS Workshop 3 Participants

FROM: Power Pundits LLC

RE: Workshop 3

DATE: April 26, 2013

As ordered by the Arizona Corporation Commission related to its 2013 Renewable Energy Standard Implementation Plan, Arizona Public Service Company is conducting a multi-session Technical Conference with stakeholders to evaluate the costs and benefits of distributed renewable energy and net metering. The sessions are designed to bring together stakeholders holding a wide range of perspectives, experiences, and levels of technical knowledge to evaluate these costs for all customers—both those who have access to distributed energy and those who do not. Sessions are exploring such issues as environmental mandates, changes in generation requirements resulting from adding distributed energy to the generation stack, localized grid impacts, system losses and other relevant topics. APS engaged a team from Power Pundits LLC to lead, moderate, and manage this technical conference.

Meetings in this series to date have included:

- An opening forum February 21
- A technical workshop on understanding rates and distributed energy (DE) benefits March 7
- A follow-up stakeholder call March 14
- A second technical workshop on resource planning and distributed energy costs March 20
- A third workshop, documented here, held April 11 at the APS Ocotillo site in Tempe, AZ.

Workshop 3 focused on the SAIC study and other models. The agenda included a discussion of energy subsidies, solar value studies from around the United States, a first look at the SAIC results from their recent work and discussion the SAIC analysis.

Eighty-seven stakeholders registered for this forum, including seven people who participated via a conference phone connection. Fifty-two attended in person. Copies of the agenda and presentation slides are available at www.solarfuturearizona.com. An audio recording of the workshop is also available on the site. These notes are the reflection of Power Pundits staff who participated in the workshop and are not a verbatim record. We believe they accurately reflect the sense of the day's meeting.

- ➢ In these meeting notes, action items are indicated by an arrow before the item. Questions from participants are in **bold type**. Answers are *italicized.*

Welcome and Workshop Overview (SLIDES 1-10)

Greg Bernosky, APS Renewable Energy Manager, introduced Bob Davis who is taking over for Mark Gabriel as facilitator for this technical conference as a result of Mr. Gabriel recently taking a position at Western Area Power Administration. Mr. Davis began the meeting by having participants in the room introduce themselves. He reviewed the conference purpose, workshop goals including getting to the critical challenges, where we are in the process, and today's agenda. He next briefly reviewed the major takeaways from Workshop 2 (slides 8-10).

Alignments—Moving Forward (slides 11-14)

Mr. Davis discussed the challenges many participants have expressed in understanding the alignment concept. He also noted that reaching alignment on technical issues may prove difficult to achieve. He said that it will be useful to identify major technical topics and capture the views and perspectives of workshop participants. He presented a cost and benefits table that lists 20 categories and provides a proposed description of each (slides 12-14). Mr. Davis sought a small group of volunteers to capture stakeholder views on each of these categories of costs and benefits and record it in a column on this matrix. Volunteers who self-identified are:

Rick Gilliam, Vote Solar; Jason Keyes, IREC; Marc Romito/Carmine Tilghman, TEP; James Larson, VA; Jamie Kerns, Seabreeze Power; David Berry, Western Resources Advocates; Patrick Black, Fennemore Craig, representing large customers; Michael Neery, AriSEIA; and Gary Mirich, AECC.

Qs and As

- **How do you see the differences discussed? Will they be included in the final report?**
  Yes in the final report. This might be a significant component. The matrix/ table could be a beneficial aid to all participants if we can use it to identify where we have commonality and where we have multiple views.
- Suggest a new item: We might be missing one big opportunity—looking at current operations, instead of asking how could a utility operate in the future? One example: What if we moved the peak from 5 pm to noon to better match solar peak (by load shifting)?
  Tom Hoff suggested technology synergies be used to shift load.
- Michael Neery suggested there are add benefits for solar water heating, referencing an SRP new report.

Energy Subsidies (slides 15-18)

Mr. Davis reminded participants this topic came up in the opening forum on cross subsidies and that stakeholders asked for a discussion on subsidies for all technologies. He noted that most subsidies are at the Federal level and that state-specific data is particularly challenging to find. He shared information on the categories of subsidies and how they are divided among the technology sectors. Participants also raised the issue of hidden subsidies, such as the limits on liabilities for nuclear plants. These indirect subsidies are not fully captured and are difficult to determine and use.

Qs and As

- **For tax-related subsidies, does this include fuel source also or is it only generation assets?**
- ➢ *Mr. Davis said he didn't know but would research and get back to the questioner.*
- **Is there information available on the subsidy amount per kWh generated?**
  Slide 18 provides percentages of subsidy and generation.
- **Are these numbers for the entire country? Are they available for AZ only?**
  To our knowledge, they are not available for a single state only and would be very difficult to derive.
- **Subsidies for all fuel sources should be considered. How specifically will these be considered in this technical conference? in the report?**
  We are beginning this discussion right now. The question is to determine how we advance the subsidy discussion in this process.
- **Will the report say subsidies should be considered and nothing else? Can we add a line to cost-benefits matrix on subsidies?**
  Yes we will add subsidies to the cost benefit matrix. We understand that there are different views on how subsidies should be included in rate case.
- **The data says there is a $11.B subsidy. How does this compare to the size of the electric sector market?**
  While I don't have the specific numbers, I expect subsidies are a small percentage.
- **This is only one category of subsidies. There are subsidies in current rates. It would be good to know how much earnings come in from C&I vs. residential customers or urban vs. rural. It would be nice to flesh this out so we have perspective and understand the magnitude of how these subsidies compares to subsidies for DE. Doesn't APS have data on known cross class subsidies related to DE and other factors? It's important to understand how Solar DE fits in.**
  APS provided information on the major cross subsidies in response to a stakeholder data request. It's posted on the solarfuturearizona.com website. However, APS uses average cost rate making for various classes of customers and doesn't consider every deviation from the average to be a subsidy. Rather, it's just a normal accepted outcome of the rate making process. In the case of DE, a subsidy exists because the rate design or charge types, such as kWh, kW and monthly charges do not match the cost drivers (energy, capacity, or customer count) for residential and small business customers. This mismatch is accentuated by the high level of self supply or load reduction that can be achieved through DE.
  Other rate subsidies do exist, most notably low income discounts and a general subsidy from business customers to residential customers. However, unlike the DE issue, these issues have been fully vetted in numerous rate cases. Perhaps at some point DE should be a separate rate class.
- Concerning a rate class for DE customers, what percentage of customers is in the low-income rate class? What percentage are DE customers?
  APS has 70,000 low-income customers out of 1 million or about 0.07 percent and is closing in on 16,000 DE customers or about 0.016 percent.

Participant Comments and Observations

- Solar C&I customers are providing additional benefits above their costs. This still is a cross-subsidization—just in a different direction.
- The tax subsidy discussion is important. With DE generation resources, there's no tax on the sun. Fossil generation industries get a tax benefit, depreciation, etc.
- Isn't a factor of renewables [receiving large subsidies] is that renewable is a new industry that has not yet matured? Other technologies don't need the subsidies.
- The current conversation is on rate subsidies on solar customers vs. non participants. Federal subsidies are not totally relevant to ACC rate policy. APS is not advocating changes in federal tax policy. These subsidies tend to lower costs to all rate payers equitability. APS is talking about an equity issue among ratepayers, customer-to-customer subsidization.
- If ratepayers paid the true cost of energy, renewables and clean energy technology would be a bigger piece. There are clear energy benefits. This must be a part of the discussion.

Experiences from Around the US (slides 19-51)

Tom Hoff, Clean Power Research

Mr. Hoff explained how his firm is applying DGValuator [the model his firm created] to quantify the value of solar in the APS service territory. He explained that he has been retained by IREC to conduct an analysis using the data from the 2013 SAIC Update study. His goal is to provide this information to develop stakeholder confidence in the model and to produce a range of value for various benefits from which policymakers can then assign total value.

Mr. Hoff posited that there are two big questions and three steps for answering each question:

- What are the benefits/costs of DE that should be included in determining its value?
  A. Define costs/benefits
  B. Identify who gets them
  C. Select
- How are benefits/costs calculated?
  A. Define methodology (how benefits/costs are calculated)
  B. Choose input assumptions
  C. Select method and input assumptions

He described his method as simple—not simplistic and that it answers the two questions so that the policy makers can make the selections and stakeholders can understand what went into the mix. Mr. Hoff explained that he comes to this as an objective tool builder and he hopes to raise the level of discussion in the stakeholder process by providing tools that are accessible without having to use a production cost modeling tool such as PROMOD. Mr. Hoff suggested that the APS stakeholder process fits well with the Value of Solar approach (slides 23 and 24). He stated that it's too difficult to identify all the costs and then allocate them among the customers. He suggested that instead, customers pay for all consumption and that the utility then pays customers for solar generation they provide (Value of Solar approach.)

He identified value components for the utility, ratepayers and taxpayers (slides 25 and 26). He also pointed out that his goal is to identify how to calculate the benefits—not to make recommendations for decisions. He explained that the basic approach is to separate the technical and economic value of a perfect resource and then compare how good DE is to that perfect resource.

Mr. Hoff discussed how Austin [TX] applied the Value of Solar approach. Austin calls it a solar tariff. One factor that had to be considered was applying a nodal price analysis. Using a 30 to 50 percent premium did not significantly change the output. The analysis resulted in a levelized value of 12.8 cents per kWh. Mr. Hoff noted that what he thought would be important to APS and its stakeholders was not the specific outcome of a particular utility and how they applied this approach, but the lessons from the implementation and how those might be used in AZ (see slide 33). Mr. Hoff also briefly discussed some of the differences between the benefits identified in the Austin study and in a separate study done for PA and NJ (the MSEIA Study). Both Austin and MSEIA considered values in energy, generation capacity, environmental and T&D capacity. The MSEIA study also considered market price reduction, economic development, long-term societal and security enhancement values as well.

Mr. Hoff also walked participants through the model's methodology and components and outlined calculations for each component (slides 37-49).

Qs and As

- **How are you comparing the Value of Solar approach to the next best alternative? Customers aren't paying today for some of these costs and benefits. These are not all avoided costs. Is this approach mandating insurance for future costs? How is this factored in?**
  We put PV on the same footing as natural gas generation. When you buy PV you're getting 30-year price hedging.
- **Utilities don't hedge gas out for 30 years. Consumers are not willing to pay for this.**
  Hedging is a policy question: Should it or should it not be included.
- **Hedging uses a forward curve in managing prices and the probability of future prices. Ratemaking doesn't take forward prices and levelize them for today. Coal has contracts for future escalators but utilities don't make customers buy insurance for these future escalators. The question is: Would customers want to pay for this? How can an analysis handle all of these variables on a like basis?**
  The difference in the Value of Solar approach is to eliminate all probability. Mr. Hoff noted he hasn't seen a better method to have zero risk of probability.
- **The question: "Do customers want to lock into a higher future price?" needs to be directed to regulators**
  Utilities must pay for certainty or to eliminate uncertainty. This is a policy decision. The Value of Solar analysis isn't making that decision, just providing the data. Decisions are the role of stakeholders or policy makers.
- **Has APS surveyed customers regarding their tolerance for fuel price risk?**
  APS has not surveyed customers on this topic. APS has a three-year hedge program. The utility has not asked customers how far into the future we should hedge. There is a cost of reducing risk. APS staff looks at the volatility of future prices; hedging minimizes this volatility. APS is not in the speculation (long-term outlook) business, but are working to manage volatility of fuel costs in the near term.
- **Concerning this policy, fuel costs can increase or decrease. Customers are taking on the risk in a decision made by the regulators. These costs are passed through in a fuel adjustor.**

DE customers are not bearing the full cost. Net metering spreads insurance costs across others. Current utility practices are not reflective of long-term hedges—paying for more insurance than is needed. Very few consumers enter into long-term hedges—a mortgage is one example. For most products, consumers don't hedge longer than one year. The costs and benefits of raising amount of insurance for future fuel price are too expensive.

- **In preparing an economic analysis using zero fuel price for solar, does forward pricing provide a valid comparison?**
  The question is: Who receives the benefits/costs of a fuel hedge? It's somewhere between utility and consumers. It can be viewed both ways.
- **On slide 35, there is a significant difference in findings: Austin shows a value of 12.5 cents and MSRIA shows 30 cents of value? Why is this so different?**
  It depends on which categories to which you are ascribing value. You can see similar amounts of value in the red categories on slide 36.
- **On slide 44, how do reliability concerns come into play? Solar is not always "on." How do you know what the number is for PV?**
  The model uses hourly data with and without PV. Hourly load data is required.
- **Don't you have to examine reliability by circuit?**
  The model takes a more broad utilitywide look using average T&D system inputs.
- **On environmental value (slide 45), does the model address SOx, NOx, etc.?**
  This is a placeholder and use REC prices. It's difficult to get a comparison on other attributes. If a utility is getting close to its RPS requirements, it's measured here. Other environmental benefits go into another category and are counted separately.
- **Is slide 46 comparing investing in local generating sources vs. importing fuel, etc., from other locations?**
  No, more jobs results in more local tax.
- **When we've done studies of this sort, we've looked at both sides of the equation, benefits as well as costs. For example, higher taxes reduces disposable income. Have you factored in both sides?**
  The model looks at how much it costs to build and operate a gas plant and how much it costs to build and operate a PV plant. It uses an equivalent capacity basis converted to energy.
- **Does slide 47 address externalities? What about costs for EPA controls? Over and above these costs?**
  Yes. This addresses items not covered by the REC. It's more difficult to calculate and relies on external studies to determine value. Utilities save money; more environmental value is on the table. It brings clarity to who gets the benefits.
- **In a situation where incentives are not required, how do you value the RECs?**
  Mr. Hoff said he didn't have great answers; we're not there yet. The best we can do is to leave a placeholder for discussion. Do you use voluntary REC market? He noted he could use help here from stakeholders to determine how to value this in Arizona.
- **Where does water offset fit?**
  Under environmental benefits.
- **The APS study should be a going forward study. ASU has 12 MW of DE. Great savings are available going forward by standardizing the procurement process. Actual outputs are 30 percent greater.**

This is an area where assumptions should be discussed.

- **In looking at slide 49, Market Price Reduction, is there some analysis available to help understand how this applies to AZ?**
  \Mr. Hoff stated he didn't know the AZ market well enough to provide.
- **How did the model separate the overall market move price vs. transmission congestion price? Does it assume this continue for 20 yrs? Is it double counting T&D capacity deferrals?**
  No. You wouldn't get a strong relationship between consumption and load if this was price only. How long we should consider this is a matter for stakeholders to consider.
- **How long do you consider this? The situation is that you have overproduction of solar DE in shoulder months.**
  The utility can sell energy in the market and credit revenue back to the customers.
- **Are you seeing any difference in the utility's ability to capturing off-system sales or benefits? Is there another side to capture this? How would you capture this?**
  I don't have enough experience to answer from a quantitative basis. One way you could consider this is that heat rates change over time. Use this approach and everyone can see this. There could be an argument but I don't have an easy answer.

Participant Comments and Observations

- 16,000 DE customers have hedged against utility price volatility.
- The US DOE did some research quite a quite a while ago that shows that for every dollar spent on a local utility, the community sees a 33-cent local benefit; however, if that same dollar is spent on the local economy, a $1.67 benefit accrues because the money spent in the local economy has a multiplier effect.

SAIC Distributed Energy Model and Analysis (slide 50-80)
Scott Burnham, SAIC

Mr. Burnham gave an overview of the work SAIC is doing to update the 2009 Beck study. HE reviewed the updated study assumptions (slide 52), the changes in PV characterization on APS' system (slide 53-54) and outlined the PV penetration scenarios used (slide 55) and the PV deployment assumptions (slide 56). He also reviewed the methodology for the study's value assessment (slide 57). Mr. Burnham noted that this study focuses on the incremental value of new installations because previous installations have already valued and are already included in the current resource planning situation. He reminded participants that the 2009 study was comprehensive in approach and included significant stakeholder engagement. It established a methodology that could be periodically updated. The 2013 update focuses on three target years 2015, 2020 and 2025, used actual measured performance and system observations from the increase in solar penetration on APS' system. He reminded participants that location and type of systems are a function of the market, noting that APS is agnostic about technology or geography of installations.

Since 2009, APS has seen a dramatic increase in solar penetration. Avoided energy has significantly increased, along with an increase in dependable capacity and value for APS. One key driver for the valuation change is the dramatic decrease in the natural gas forecast from that used in the 2009 study. The cost projection for CO_2 emissions also significantly changed to a further out implementation at a lower price than that used in 2009. Finally, the update captures a lower load forecast that reduced the avoided energy and deferred capacity forecasts than those data points in the 2009 snapshot.

The study examined if there is sufficient DE to defer a capital expenditure. It used a feeder by feeder analysis. The 2009 study found no value in extension of service life. The 2013 update did not go back and reanalyze this, but took this conclusion and projected it forward. A similar approach was taken for reduction in equipment sizing. The study looked at deferments on both the 69-kV sub-transmission system and on the transmission system, specifically focusing on load growth and constraints for new generation ties. The load analysis was conducted by SAIC using APS-provided PROMOD runs. Mr. Burnham reminded participants that deferring capacity additions results in deferring related transmission investments. For generation, the study examined avoided energy and deferred capacity based on solar DE penetration. The study looked at target year nominal values ($/MWh) and in present value, discounting back to 2013 dollars.

Qs and As

- **Why did this study only look at new systems not already installed DE? Why didn't it consider the impact to current systems, when net metering will have an impact on them?**
  The study is looking at the incremental value of new solar systems. Systems in the ground have already received some value. Similar to the 2009 study, this update is meant to be a marginal incremental study. Therefore, it's looking at the marginal impact on APS' system and looking to capture the marginal difference.
- **Gas prices are 25 % higher than at the end of 2012? Can we change this input?**
  We've run some sensitivities with different gas prices to look at the impacts. Charles will show them to you in his presentation.
- **Concerning the lower load forecasts, where is the data coming from? What about the reduction in energy being purchased? Aren't new customers being added? Does this factor in new home construction?**
  The study uses APS' Integrated Resource Plan including estimated forecast load. In the 2009 study lots of growth was anticipated. This forecast was pushed back. The load growth is not there because of the economic recession. This, in turn, impacts how you look at future resources.
- **Were sensitivity runs done for each key driver or just for natural gas?**
  They were done for natural gas and CO_2 as well as different DE penetration scenarios.
- **The number of DE installations and their output is dynamic. Today's inverters are increasing efficiency. New systems will be better. How is the study capturing that?**
  The scenarios capture increases/improvements. The study looks at total energy output (kWh.
- **The 2009 study used estimates because data wasn't available. Have you now gone out and collected data on installations and solar outputs?**
  APS is ramping into production metering on residential DE applications, but is including actual production from a number of systems.
- **In slide 5, it says the study used estimates of 1,650 kW residential output and 1,500 kW commercial output used in study?**
  Yes, we also have actuals from Flagstaff to validate these numbers.

- **What is the rationale for developing the different scenarios? It's not the RES that's driving installations, it is consumer choice.**
  Only the low scenario was anchored by the RES. The expected case is based on current trends.
- **Slide 7 discussed energy losses. Why does the study need to consider energy losses?**
  The study must place a value on energy losses in the APS system. Conventional resources don't have to produce 1.07 kWh of energy for every 1 kWh of DG. This has a value.
- **During the day time, are losses higher than 7% if this is the average? Is the 7% average measured on systems with solar PV? For instance, are daytime 9% losses and nighttime 5%? If there's higher load, higher losses, do the savings accrue to everyone?**
  APS provided measured data at the feeder for losses. The study did not look at marginals.
- **If the approach is incremental and not looking at already installed, will it take longer to get to the next avoided capacity?**
  Yes, it will take longer.

Distribution System
Joni Batson, SAIC (slides 58-63)

Ms. Batson discussed the distribution system elements of the 2013 Update. She said that unless APS can target DE deployments, it will be difficult to deter upgrades. For this study, SAIC examined the APS distribution system to see what's happened to date. SAIC focused on 63 feeders with significant solar installations (< 10%). The study asked, "Would upgrades have been done without solar?" In the expected case, only five feeders would have deferred upgrades. In the growth scenarios, this rises to nine feeders—or an increase of 30 percent. For most feeders, the results were no change. This result is somewhat insignificant (5 feeders out of 1,340) The study concluded, that if the solar install is not on a on constrained feeder, no value is assigned to distribution capital deferral The study also looked a projected peak loads to see how much could be reduced. This analysis showed a deferral for one year in 2020 in the expected case and a two-year deferral at high penetration rates. However, none of the 10-year transmission plans fell in the 2020 range (slide 62).

Qs and As

- **Did the study look at reactive power? Do PV installations contribute to this need or do they offset it?**
  The relationship between DE and reactive power was not examined as part of this study.
- **Did this study back out solar, on a peak capacity value or on a time basis (15- minute or 1-hour basis)? Perhaps there's a tie to Tom Hoff's approach? If solar is 1 % capacity to total system, is this proportional?**
  The study looked at time of feeder peak based on typicals (TMY). This may be proportional; it's a tiny sliver of the stack of value.
- **Concerning total feeders, what about homes without feeders? This should be a long-term study over years so new construction can be factored in.**
  The study considered new load projections compared to existing feeders. This approach tells you where you need new feeders.
- **How many feeders would need to be upgraded without solar?**

Likely more than 9, but typically 2 to 3 percent of total feeders. This means major thermal upgrades (new wire, new structures) not capacitors.

- **If APS is seeing only 25 or 30 upgrades, and of those, if 9 are deferred, isn't this a reduction of 1/3 of the planned upgrades?**
  Yes.
- **On slide 60, is 11.05% the carrying charge? This seems low.**
  This included financing, depreciation and taxes. This is a long-term asset with a 40-year service life.
- **Slide 60 shows projects that could be deferred and how much solar needed for these deferrals. If we don't know where DE systems are being installed, how do we know the impacts?**
  This is based on averages.
- **On slide 63, are these transmission system capital deferrals generator tie installations?**
  Yes on average. Some generation doesn't require transmission but this is an average.
- **What can you tell us about the difference between the expected and high case in slide 63?**
  Ms. Batson referred this question to Mr. Janechek. He explained that energy gets avoided with all DE installations. Capacity doesn't get avoided, it gets deferred as load grows. If solar is delaying the need for additional CTs, it's deferring and not avoiding. This is what you're seeing between these cases.

Patrticipant Comments and Observations

- If APS took a more active role in placing solar, we'd have better data. Perhaps this is a reason to pay premiums.

Generation Analysis

Charles Janechek, SAIC (slides 63-71)

Mr. Janachek noted that lower gas prices reduce the value of avoided energy. He stated this was also true for carbon prices (see slide 65). The range of avoided energy values is projected to be from $13 M in 2015 to $162.5 M in 2025 in the expected case (slide 66). Because of diminishing dependable capacity, solar DE's contribution to peak decreased with increased solar PV in a non-linear fashion (slide 67). Based on this study, a blend of gas generation plus purchase power will be deferred by 2020. This is expected to include two CTs by 2020 and 3 CTs by 2025 in the expected cast (slide 69). Generation capital deferrals amount to $45 M in the expected case in 2025 (slide 71).

Qs and As

- **How much confidence should we have in the load forecast? No sensitivities were conducted. APS has had low forecasts in the past.**
  Every utility has load forecasts that miss the mark. In 2009, APS was projecting more than originated. These are planning studies and assumptions have to be made.APS is looking at solar penetration of load. All data used as inputs (solar energy, etc) resulted in higher solar. This translates to higher avoided energy costs. The scenarios provide for a range and include a high-penetration scenario.
- **On slide 66, what's been updated?**
  The study used the 10-year rolling average of system load shape from 2011 back.

- **What assumptions were used for the PROMOD inputs? Coal retirements? Generation mix?**
  Inputs were largely based on the most recent resource plan.
- **The gas forecast is up 22% since the end of 2012. In shoulder months gas should be going down, but we're not seeing this. Can the study be run again with current day higher prices?**
  At some point, you have to pick your assumption and go with it. Gas prices will continue to change. We have a 30% increase in gas prices in the sensitivity run. Because this price uptick is counter intuitive, we might expect prices to decline at some point in the next few months. Volatility typically happens on the front end of the price curve, not on the long term and this evens out and would generally be within the bounds in the sensitivity studies we did run. Gas prices will move around, loads will move around and the sensitivity studies accommodate this movement.
- **On slide 66, is the 20% increase for today's purchases or for 2020 or 2025 purchases?**
  Mr. Janechek said he didn't know. Without running model every day, the study can't capture the volatility.
- **In considering MW of PV, is this MW of nameplate PV? At zero load growth, increasing PV as a percent of load how does this result in diminished capacity value?**
  This is not a static load, but a percent of penetration of load; increasing the percent of load that becomes solar.
- **APS now has 98 MW of residential PV. At 7 kW average x16,000 systems = 9,800 kW. Residential retrofits average 2.5 MW/month, or 30 MW this year. This is 4,200 systems; 1500-1600 homes, half are in APS service territory. The capacity of solar is not increasing as fast as load growth. If PV capacity doesn't outstrip load growth, we're still at high value. Are we on this curve?**
  If penetration percentage does not increase but holds steady, solar would stay at same place on curve. However, projections call for increasing solar penetration, so we are on a curve toward diminishing capacity value.
- **What is the value of solar? Have you looked at changes to the value that changes the penetration rate?**
  These are built into the three deployment scenarios.
- **Going back to avoided energy value, this shows increasing losses at 3 cents. Does this seem reasonable? Is this based on 2016 forecast for natural gas prices?**
  Mr. Janechek said he wasn't sure of the exact amount. It is based on the variable component of avoided costs. I thought it was higher than 3 cents in 2025. The amount is fairly consistent across all scenarios. It's a function of the PROMOD modeling of the resources on the system.
- **What happens when solar doesn't impact peak? Does it shift to 7 pm in 2025? Do you take off the increasing solar (110 MW)?**
  In 2015, this is 111 MW of peak reduction.
- **Slide 67 shows 1,500 MW in 2025. System peak shifted, solar peak doesn't shift. What about storage? To meet peak, are additional resources required? What's the most economic resource to meet this need? Storage? CT? New tech that doesn't exist today? Don't know. Perhaps non technology options will be available to help shift peak? Daylight savings time?**

APS has significant TOU penetration. The utility has experimented with demand response programs. It looks at what's most economic and will continue to look at this. New programs include a home energy information pilot program. Today's answer is natural gas.

- **Power plant utilization is low. Does it make better sense to own a plant to serve one hour? Would it be a better option to purchase?**
  Owned or purchased, this is still an expensive resource. This is not making a decision on ownership. The utility still needs capacity or demand response, storage or a resource (owned or purchased).
- **Is this deferring construction of power plants?**
  Yes, it's deferred capacity.
- **What happens when the market opens up? Will APS relook at this?**
  If there's a major regulatory shift that impacts solar, APS would need to relook at this.
- **With 250 MW of solar DE already installed, does this show deferring more CTs?**
  The base case already has pre-2013 solar installations built into scenario (14,000 current installs). The system owners are already getting credit for this. Current solar has a higher capacity value than future solar. When load resources balance is considered in 2020, it includes the 14,000 installations already in equation.
- **The base case reflects current installations, net costs and benefits. For the future, policy changes, rate case, etc., should apply to new installations.**
  That's a rate design question; I don't know if or how pre-2103 installations would be treated in the future if rate design changes. This study is only looking at deferred capacity.
- **On slide 72, why is the value of the high penetration scenario lower than expected?**
  This is a function of accounting and total of construction needs. Both the high and expected cases are expected to defer 3 CTs. The high penetration case pushes out the need for a CT from 2023 to 2024. Cumulative spending is a little higher because of the time value of money.
- **Can we get valuation on storage? Solar water heating vs. PV? Maybe this would motivate people to add battery systems? Or use electric vehicle storage/battery?**
  This particular study is a solar PV study update.
- **The Corporation Commission asked for a DG study, not a PV study. Why isn't solar water heating included here? There is obviously a benefit there.**
  This study is purely a PV study. Other measures aren't part of this study. Some of the other DG components are more difficult to quantify. The most dramatic growth is in solar PV.
- **How do you know if you haven't measured solar water heating changes?**
  The 2009 study did include solar water heating.
- **When will solar hot water heating be included or an analysis done?**
  This study focuses on total energy penetration from solar PV and energy production from solar PV. It involves a blend of PV production and offsets. As potential solutions are identified, quasi storage of solar hot water heating can be described as APS takes its solution forward.
- **Why are APS numbers so much lower than those from Austin or the East Coast study discussed earlier today?**
  It's in the assumptions: resource mix and gas price assumptions. A 30-percent increase in gas prices results in a 20-percent difference in avoided energy costs. An APS representative added this explanation: On slide 36 of Tom Hoff's presentation, energy is cleanest and

simplest of the calculations, it's the fuel source you're avoiding. He shows an avoided energy cost of 10 cents/kWh ($100/MWh). Mr. Janechek conversely is talking about updated gas prices and a CCT heat rate of $7-8. You can take the gas price of $4 times the heat rate of $8 and get $32/MWh. That's a pretty common understanding of a marginal cost. I have no idea how the $100/MWh figure came from.The avoided energy costs is likely to be the same on a $MWh basis in all of these studies.

- **Concerning natural gas, how far are futures is being projected? Does the study use a 20-year forward rate for gas or this is an obvious shortcoming?**
  The study uses the gas forecast in the target years –2015, 2020 and 2025. Austin used a 30-year levelized gas cost.
- **Can SAIC chart the MW and systems you're assuming? Can stakeholders get the inputs?**
  As shown earlier today, the expected case in 2015 shows 242 MW. The report will have the high and low cases in addition to the expected case.

Participant Comments and Observations

- As you get rebates down, solar penetration decreases. Leases are already pretty tough.

SAIC Study Conclusions

Scott Burnham (slides 72-80)

Mr. Burnham reviewed the study conclusions with participants. The major takeaways include:

- The ratio is higher in the low penetration case and is lowest in the high penetration case in 2025 (slide 73)
- In 2025, the variable components piece remains steady across the penetration scenarios. Fixed prices change based on the penetration scenario (99 cents—low; 86 cents—expected; and 65 cents—high. (Slide 73)
- In 2025, the preponderance of value is in fuel and purchase power avoided costs (6.13 cents out of 8.178 cents) (slide 75)
- The net present value is 3.55 cents/kWh (slide 75). This breaks out to: Distribution—0 cents; fixed O&M—0.08 cents; transmission—0.3 cents; generation—1.66 cents; and variable costs (fuel, PP, emissions, gas transmission)—6.13 cents/kWh. (slide 75)
- 2015 is too soon in the planning horizon for any savings to show up
- Energy savings do exist in short term –1.07 kWh of avoided energy for each solar DE kWh
- Increased penetration = increased savings. This is a non linear relationship; thus the need to run PROMOD to understand hourly dependable capacity
- Solar PV does provide value—how you get to that and what that value is are the questions to be answered.
- This study is guided by the 2009 study methodology; it features changes in input assumptions.
- How you interpret data and how you make the choices are policy choices

Qs and As

- **On slide 73, you mentioned the difference in the rate of change between the high and low scenario. What did you mean concerning the rate of change?**
  Rate of change relative to changes in 2025-2.7 million MWh in the expected case compared to 5.4 million MWh in the high case in incremental solar energy in MWh. The ratio is driving the difference.

- **Can stakeholders get a simplified version to manipulate inputs?**
  SAIC has run sensitivities for the stakeholders and will share them today.
- **It appears solar penetration and fuel costs are driving these results. Can you produce a table showing variations in these two variables and how they fall out?**
  See slide 75 for an example of penetration changes. Fuel cost is in the PROMOD runs.
  - **The current present value is 3.55 kWh compared to Austin and PJM study values. Why is this so low?**
  The SAIC study and prior RW Beck study do not look at externalities and the policy and cost implications from externalities.
  - **This study is saying power in 2025 is worth 3.55 cents now. You'd pay someone that amount to generate in 2025? Would this be the same for natural gas?**
    Yes, you're discounting the time value of money back to today's value.
  - **Was there a table in the Beck study?**
    Yes but it's not displayed in a waterfall chart.
  - **Why wasn't this done for every year so we could levelize the cost?**
    The study design was a snapshot; using the same approach as the 2009 study.
  - **Has SAIC done similar studies for other utilities?**
    Yes, but every study is unique. Every situation is different. Distribution and transmission analysis and outcomes have been similar.
  - **The previous study showed the value of solar to be 7 to 9 cents? Is this similar?**
    SAIC urges caution that for the 2009 study, the range was not tied to any specific scenario. It is similar but not exact.
  - **Does the waterfall chart show the expected case scenario?**
    Yes, the report will have values for the different scenarios.
  - **Wasn't the 2009 study range derived by combining a range of options, including those that were mutually exclusive?**
    Yes.
  - **What is the forward price for natural gas for 2025? Is there a difference in the price used in this study vs. the spot price?**
    The numbers were from the forward curve at that time See slide 78—7.66. The study used December 2012 forward prices.
  - **APS used a discount rate of 7 cents. Gas discounts rate lower. If this is further out, does that lower the value?**
    Yes.
- **In the cases shown on Slide 79, RES compliance is the measure for the low case. Is that the same for the 2009 study?**
  The 2009 study low case was not tied to RES compliance.
- **This study shows a value of 7 to 14 cents. What are the 2009 numbers?**
  The waterfall in 2009 was hypothetical and included mutually exclusive options. The high scenario in the 2009 study was equal to RES compliance in 2025 (or equivalent to the low scenario in the 2013 study.)

Participant Comments and Observations

- Utilities look at 30-year investments with levelized costs. Yet here, we're looking at nominal costs. We should see equivalent levelized costs here. These will be higher.
- On slide 76— the marginal piece? The change in solar at that point (incremental piece). In 2025, there will be three times more solar than is installed now? Should we move toward an even lower penetration scenario and figure out what to do then?

Closing comments and wrap up
Bob Davis, (Slides 81-83)
We've posted 24 studies on the Website. Answers to the stakeholder data requests are almost all complete and posted. Meeting notes will be posted this week.

Next steps are to finalize the schedule. Potential speakers include Ron Binz, a former CO regulator; Chris Yonkers, from SDG&E; a SEPA representative to discuss utility models found around the nation; APS potential solutions; and stakeholders on cost and benefit perspectives. If the speakers are available, the proposal is for the next meeting to be held May 9.

For stakeholders who've volunteered to work on the cost and benefit table, we'd like to get it back from the working group and posted before the next meeting for all the stakeholders for review. We will also follow up with Tom Hoff to determine when his results will be available before the Closing Forum, perhaps in early June.

Qs and As

- **Does the ACC order have a deadline for submittal?**
  There is no deadline in the ACC order. However, Commission staff requested APS provide as much information as possible so the Commission can make a decision on the utility's 2014 implementation plan.

Roundtable discussion on Study Sensitivity Scenarios
Scott Burnham and Joni Batson, SAIC
Slide 1 shows the results of a sensitivity run on natural gas prices (30 percent change in gas prices). This results in a 17 percent change in value. Slide 2 shows results from a sensitivity run on CO_2 prices ($0 to $39.44). Screen shots of distribution feeder analysis, sub-transmission analysis and system peak reduction analysis were also shared.

Qs and As

- **What are the penetration assumptions for the 2009 study?**
  Assumptions about natural gas prices are driving the major changes.
- **Can SAIC do a sensitivity run on load growth?**
  Would that already be captured in low and high scenarios? Isn't that within the solar MWh numbers?
- **If the load shape is not static and the study is using a longer term trend, what does that mean? Even without solar, the peak hour is moving later.**

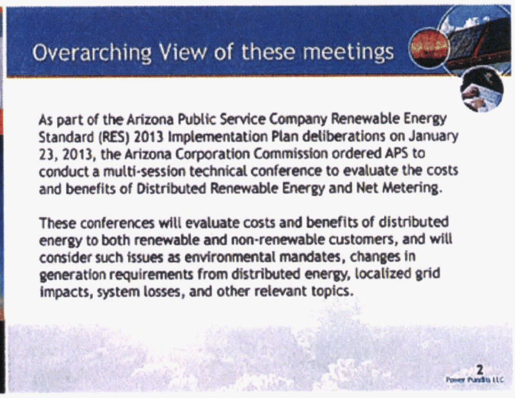
While load may be growing, the peak and use patterns are not changing. Changes are occurring with different EE or DR implementation.

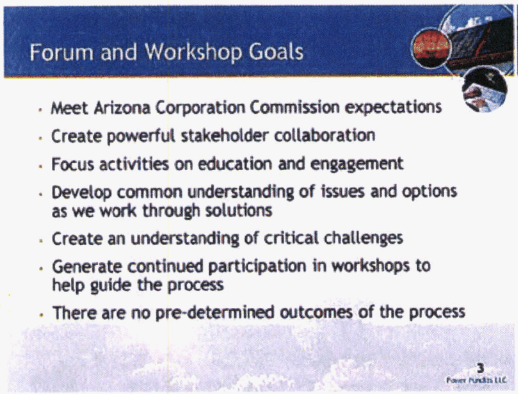
- **How is peak load shape changing over time?**
  In modeling, load shape doesn't significantly change.

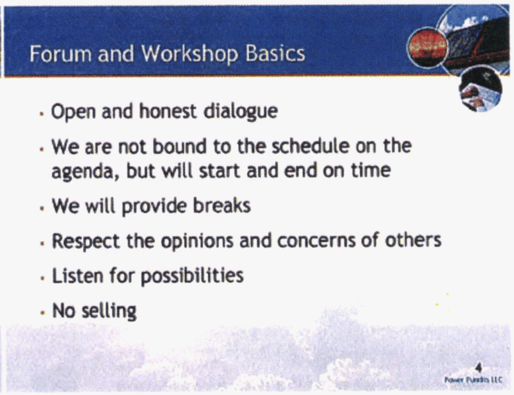
The workshop concluded at 3:30 p.m.

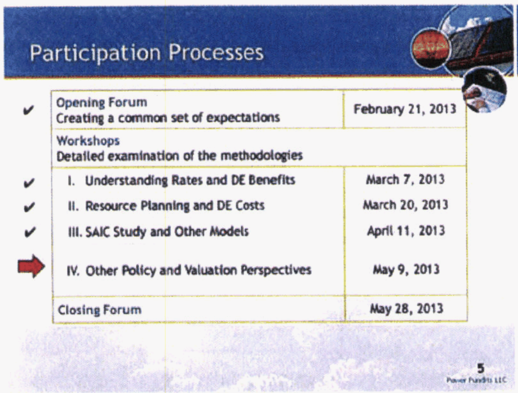
Workshop IV (May 9, 2013)

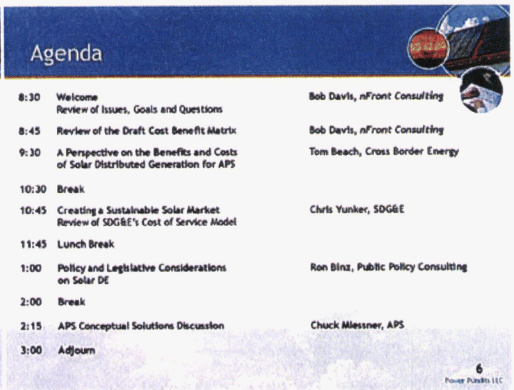
Presentations











The Benefits and Costs of Solar Distributed Generation for Arizona Public Service

Tom Beach

Crossborder Energy

May 9, 2013

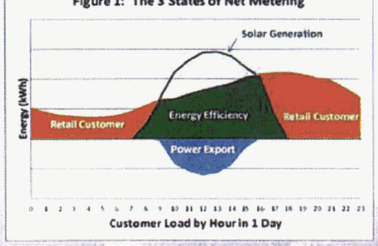
Crossborder Energy 7 Power Pundits LLC

Scope

- How demand-side solar will impact APS's ratepayers.
- A RIM test - the "no losers" test
- Evaluates solar DG, not NEM
- Solar DG is a long-term resource.
  - 20-year time horizon for the analysis
  - Similar to other resource evaluations
- Recognizes short lead times / scalability of DG
  - 1,150 MW of demand-side resources before 2017
- Uses data from 2012 IRP and Beck / SAIC work

Crossborder Energy 8 Power Pundits LLC

Figure 1: The 3 States of Net Metering



Crossborder Energy 9 Power Pundits LLC

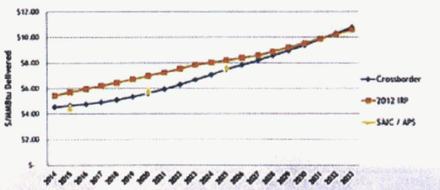
Benefits and Costs

- Benefits
  - Energy
  - Capacity
  - A/S & Capacity reserves
  - Transmission
  - Distribution
  - Environmental
  - Avoided Renewables
- Costs
  - Lost retail revenues
  - DG Incentives
  - Integration costs

Crossborder Energy 10 Power Pundits LLC

Energy - Natural Gas

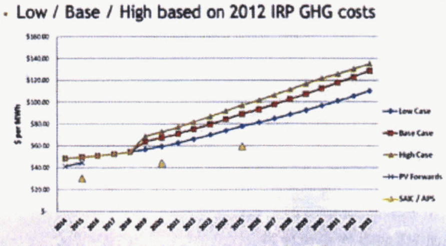
- Energy costs of the marginal long-term gas-fired resources
- Gas cost forecast uses current forward market prices.
- Very similar to SAIC / APS forecast for 2015, 2020, 2025



Crossborder Energy 11 Power Pundits LLC

Energy - Peak Months (Jun - Sept)

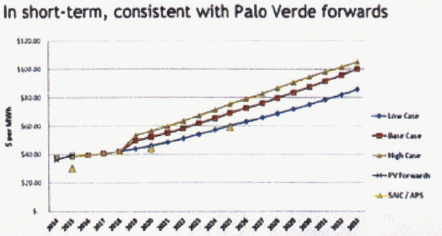
- New CT energy costs: 9,400 Btu/kWh heat rate
- Low / Base / High based on 2012 IRP GHG costs



Crossborder Energy 12 Power Pundits LLC

Energy - Off-Peak Months (Oct - May)

- New CCGT energy costs: 7,300 Btu/kWh heat rate
- In short-term, consistent with Palo Verde forwards



Crossborder Energy 13 Power Pundits LLC

Energy Benefits

Case	Methodology	Avoided Energy Costs (20-year levelized c/kWh, 2014 $)		
		Jun-Sept	Oct-May	Wtd. Annual
	Solar DG Output:	35.5%	64.5%	
Low	New CT (June-Sept) and CCGT (Oct-May). Zero GHG costs.	7.5	5.8	6.4
Base	New CT (June-Sept) and CCGT (Oct-May). Base GHG costs from 2012 IRP.	8.2	6.4	7.1
High	New CT (June-Sept) and CCGT (Oct-May). High GHG costs from 2012 IRP.	8.7	6.8	7.5

Crossborder Energy 14 Power Pundits LLC

Capacity Benefits

Component	Value	Source
CT Capital Cost	$1,376 per kW	SAIC April 11, at 66 and 73. Also, 2012 IRP, at Attachment D.3.
x 11.17% carrying charge	$153.7 per kW-yr	SAIC April 11, at 66.
+ Fixed O&M	$6.6	SAIC April 11, at 73. Escalated at 2.5%
+ Pipeline Reservation	$29.8	EPNG Tariff, assumes 2.5% escalation
= Annual Capacity Costs	$190.1 per kW-yr	20-year levelized value
x PV ELCC - Fixed Array	50%	Beck Study, at Table 5-2. Also, 2012 IRP, Attachments D.1(a)(1) and D.3.
+ Capacity losses	11.7%	SAIC April 11, at 59.
Fixed array - South-facing	6.7 cents per kWh	*Assumes 1,575 kWh/kW; see SAIC April 11, at 57.*

Crossborder Energy 15 Power Pundits LLC

A/S and Capacity Reserve Benefits

Component	Cost Basis	Percentage	Value (cents/kWh)
Ancillary Services	Avoided energy costs (CAISO study)	7%	0.5
Capacity Reserves	Avoided generation capacity costs	15%	1.0
Total			1.5

Crossborder Energy 16 Power Pundits LLC

Transmission Benefits

Component	Value	Source
Transmission Cost	$145 million	Beck Study, at Table 4-1. Escalated to 2014 $ assuming inflation at 2.5% / year.
÷ Capacity	400 MW	
+ Subtransmission Cost	$29.5 million	SAIC April 11, at 63.
÷ Capacity	130 MW	
= Transmission costs avoided	$589 per kW	
x 11.05% carrying charge	$65.13 per kW-yr	SAIC April 11, at 66.
x PV ELCC - Fixed	50%	
Fixed array - South-facing	2.1 cents per kWh	Assumes 1,575 kWh/kW; see SAIC April 11, at 57.

Crossborder Energy 17 Power Pundits LLC

Distribution Benefits

Component	Value	Source
Distribution costs avoided	$133 per kW	Beck, at 3-13. Escalated to 2014 $ assuming 2.5% inflation per year.
x 11.05% carrying charge	$14.70 per kW-yr	SAIC April 11, at 66.
x PV ELCC - Fixed	50%	
x Fraction of distribution circuits with avoidable costs	50%	
Fixed array - South-facing	0.2 cents per kWh	Assumes 1,575 kWh/kW; see SAIC April 11, at 57.

Crossborder Energy 18 Power Pundits LLC

Environmental Benefits

Category	Avoided Emissions (tonnes or AF per GWh)	Value (20-year levelized $ per tonne or AF)	Avoided Cost (20-year levelized $ per MWh)
SO_2	0.0023	$11,144	$0.025
NO_x	0.0461	$6,926	$0.319
PM 10	0.0125	$1,642	$0.021
Water	0.9728	$1,114 per AF	$1.084
Total ($ per MWh)			$1.449
Total (cents per kWh)			0.1

Crossborder Energy 19 Power Pundits LLC

Avoided Renewables Benefits

- Customer DG uses private capital, not ratepayer dollars
- Contributes to meeting or exceeding RES requirements
- Diversifies the resource mix and operating risks
- Includes difficult-to-quantify benefits
  - Price mitigation
  - Grid security
  - Employment benefits
  - Hoff et al. valued these at $100 - $140 per MWh in NJ and PA.
- Calculated for APS based on differential revenue requirements
  - 2012 IRP Base vs. Enhanced Renewables portfolios
- 4.5 cents per kWh

Crossborder Energy 20 Power Pundits LLC

Costs of Solar DG

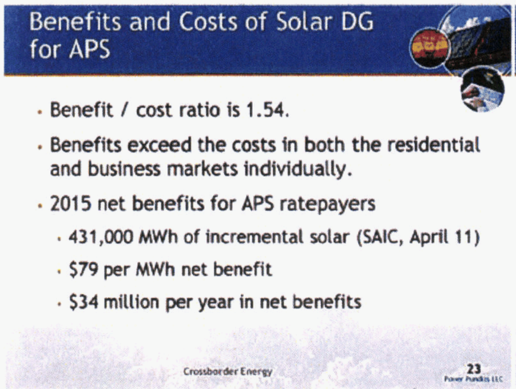
Cost categories	Costs (20-year levelized cents per kWh)		
	Residential	Commercial	Average
Distribution of systems	*44%*	*56%*	*100%*
Lost retail rate revenues	19.7	9.0	13.7
DG incentives	0 to 0.6	0 to 2.3	0 to 1.6
Integration costs	0.2	0.2	0.2
Total Costs	19.9 to 20.5	9.2 to 11.5	13.9 to 15.5

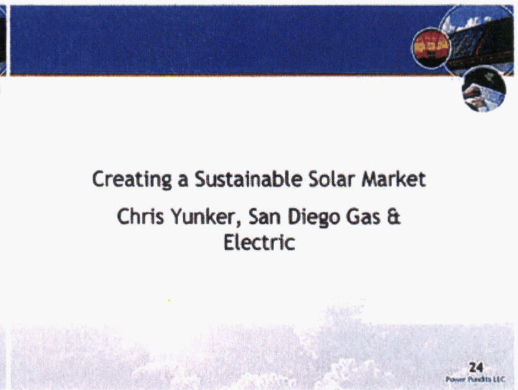
Crossborder Energy 21 Power Pundits LLC

Benefits and Costs of Solar DG for APS

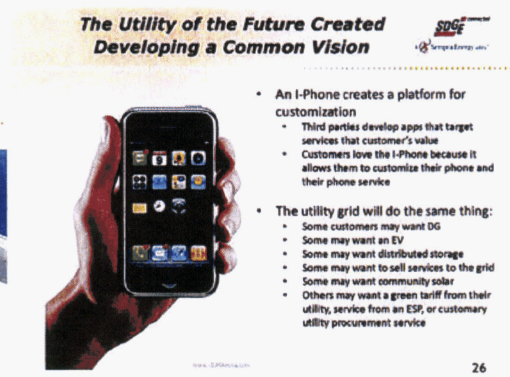
Benefits	20-year levelized cents per kWh (2014 $)
Energy	6.4 to 7.5
Generation capacity	6.7 to 7.6
Ancillary services & Capacity reserves	1.5
Transmission	2.1 to 2.3
Distribution	0.2
Environmental	0.1
Avoided Renewables	4.5
Total Benefits	21.5 to 23.7
Costs	**20-year levelized cents per kWh (2014 $)**
Lost retail rate revenues	13.7
DG incentives	0 to 1.6
Integration costs	0.2
Total Costs	13.9 to 15.5

Crossborder Energy 22 Power Pundits LLC

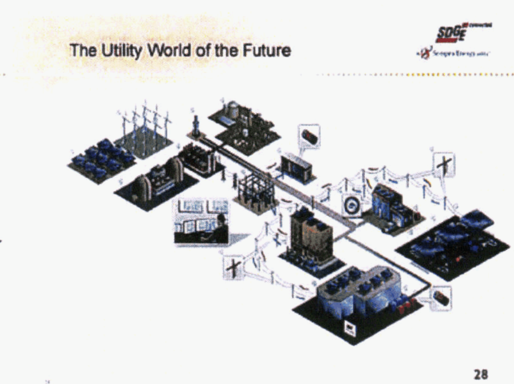

Benefits and Costs of Solar DG for APS
Benefit / cost ratio is 1.54.
Benefits exceed the costs in both the residential and business markets individually.
2015 net benefits for APS ratepayers
431,000 MWh of incremental solar (SAIC, April 11)
$79 per MWh net benefit
$34 million per year in net benefits
Crossborder Energy
23
Power Pundits LLC

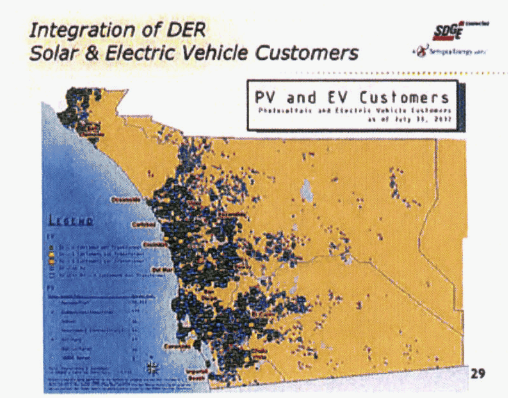

Creating a Sustainable Solar Market
Chris Yunker, San Diego Gas & Electric
24
Power Pundits LLC

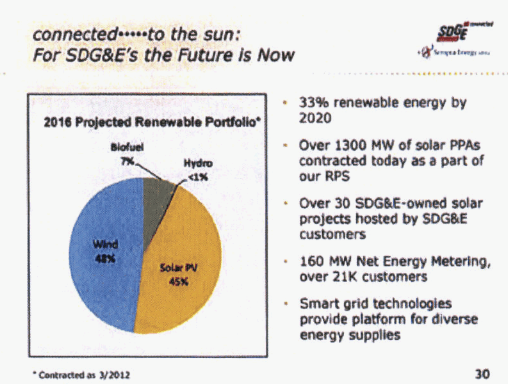

Sustainable Solar Adoption
SDG&E
25


The Utility of the Future Created Developing a Common Vision
SDG&E
An I-Phone creates a platform for customization
Third parties develop apps that target services that customer's value
Customers love the I-Phone because it allows them to customize their phone and their phone service
The utility grid will do the same thing:
Some customers may want DG
Some may want an EV
Some may want distributed storage
Some may want to sell services to the grid
Some may want community solar
Others may want a green tariff from their utility, service from an ESP, or customary utility procurement service
26


The Utility World Today
SDG&E
27

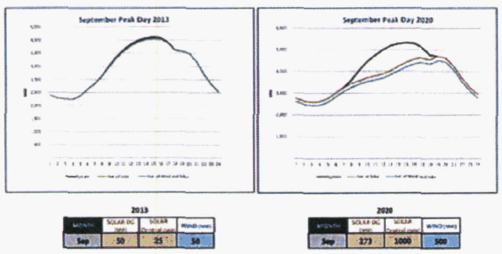

The Utility World of the Future
SDG&E
28


Integration of DER
Solar & Electric Vehicle Customers
SDG&E
PV and EV Customers
Legend
29


connected•••••to the sun:
For SDG&E's the Future is Now
SDG&E
2016 Projected Renewable Portfolio*
Biofuel 7%
Hydro <1%
Wind 48%
Solar PV 45%
33% renewable energy by 2020
Over 1300 MW of solar PPAs contracted today as a part of our RPS
Over 30 SDG&E-owned solar projects hosted by SDG&E customers
160 MW Net Energy Metering, over 21K customers
Smart grid technologies provide platform for diverse energy supplies
* Contracted as 3/2012
30

System Planning
What drives capacity requirements

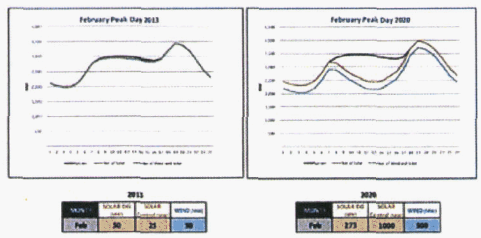
Net Impact of Solar & Wind on Peak Load



31

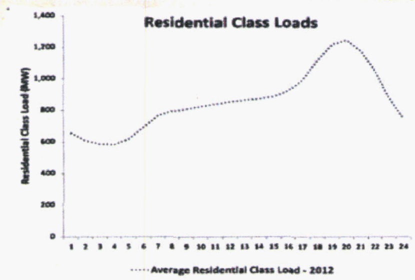
System Planning
What type of capacity will be required

Net Impact of Solar & Wind on Peak Load



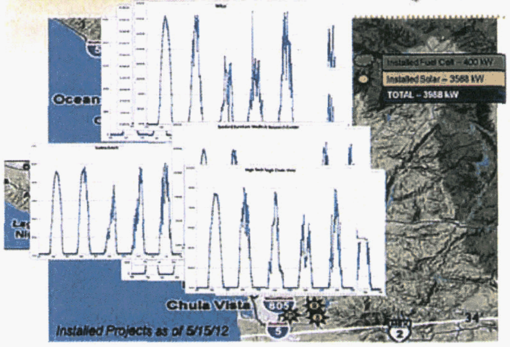
32

Distribution Demand



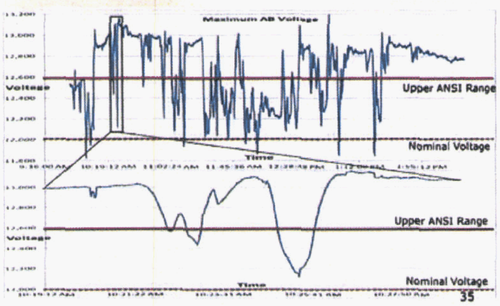
33

Resource Diversity



34

PV Issues - Intermittency



35

A Market for a Common Vision
Cost of Services Approach

Pricing that reflects the services that are available to customers on an unbundled basis

- When customers receive a service they should pay for that service
- If customers provide a service/benefit to utilities, they should also be compensated for that service
- We must identify what services customers with new technologies will want from utilities and may be able to provide to utilities
- If subsidies/incentives are needed, they should be clearly identified, equitably recovered from all customers with a plan for what will happen to that subsidy over time

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Illustrative: *Technology Services Alignment with Today's Residential Utility Rates*

Example Services	Customer Owned Solar Inc. Grid Cost/Utility Avoided Cost		Smart Inverter Inc. Grid Cost/Utility Avoided Cost		Battery Inc. Grid Cost/Utility Avoided Cost	
Grid Services Captured by Typical Residential Rate Structures (kWh)						
Energy	X	X				
Grid Services Typically not Captured by CA Residential Rate Structures						
Generation Capacity	X	X				X
Transmission Capacity	X	X				X
Distribution Capacity	X	X				X
Ancillary Services	X			X		X
Voltage Regulation	X			X		X
Load Balancing	X					X

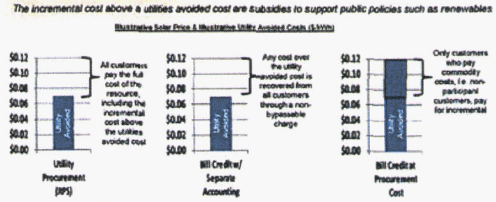
"X" – denotes potential increases to grid costs or potential utility avoided costs

The services from technologies such as Smart Inverters and Batteries, that support the integration of low carbon technologies such as solar, do not receive a price signal for the value they provide

37

Equitable Recovery of Policy Costs
Utility Procurement Costs and Bill Credits

The incremental cost above a utilities avoided cost are subsidies to support public policies such as renewables



Either through an RPS or Value of Solar Tariff all customers pay for incremental costs

Either through an RPS or Value of Solar Tariff all customers pay for incremental costs

Note: Even in this case a non-participant is not totally indifferent as they do not receive the same level of renewable credit that they would under a like level of RPS procurement

The cost of societal benefits increases for non-participants because less people contribute to the incremental costs

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California's Residential Rate OIR

- A Ruling, issued on the November 11, 2012, setting forth following ten Principles for evaluating Optimal Rate Design:
  1) Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost
  2) Rates should be based on marginal cost;
  3) Rates should be based on cost-causation principles;
  4) Rates should encourage conservation and energy efficiency;
  5) Rates should encourage reduction of both coincident and non-coincident peak demand;
  6) Rates should be stable and understandable and provide customer choice;
  7) Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals;
  8) Incentives should be explicit and transparent;
  9) Rates should encourage economically efficient decision-making;
  10) Transitions to the new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.

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Policy and Legislative Considerations on Solar DE

Ron Binz, Public Policy Consulting

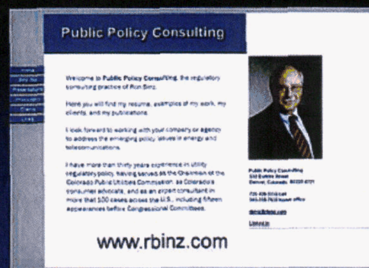
40

The Evolution of Net Metering, Rate Design and the Utility Business Model

APS Solar Workshop

Comments of Ron Binz
Public Policy Consulting
May 9, 2013

Public Policy Consulting



Overview

- What objectives should Solar DG policies hope to achieve?
- How to deal with the false precision of cost allocation and rate design.
- Unbundling the utility-DG generator relationship
- Is Net Energy Metering acceptable as "rough justice"?
- Some guiding principles

Policy Objectives

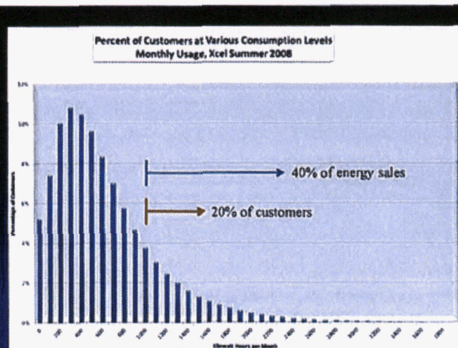
- Encourage solar deployment
  - Satisfies RPS requirements
  - Cleaner+Greener as a resource
  - "Infant industry" support for PV (cf., PURPA and U.S nuclear investment in 60s,70s & 80s)
  - Responds to popular support
- Diversify generation supply
  - Viewed as a system resource
  - Cf. Germany
- Reinforce grid
  - Relieve distribution costs and pressures
  - Enables microgrids

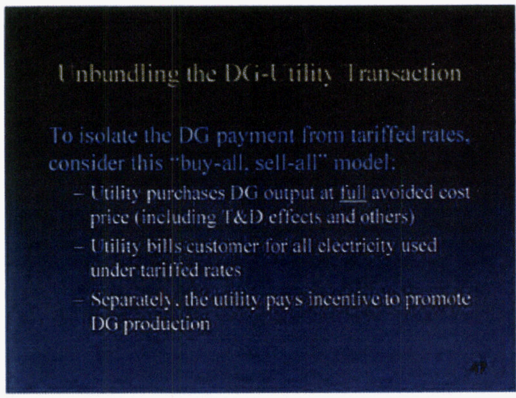
Rate Design Issues

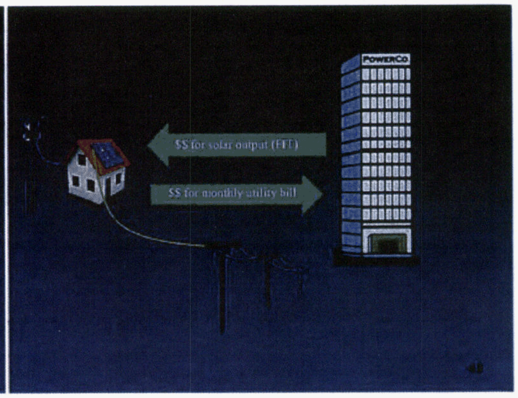
- Rate design sends the correct price signal when price equals marginal cost
- In a regulated environment, P = MC may not correctly compensate a utility, i.e.,

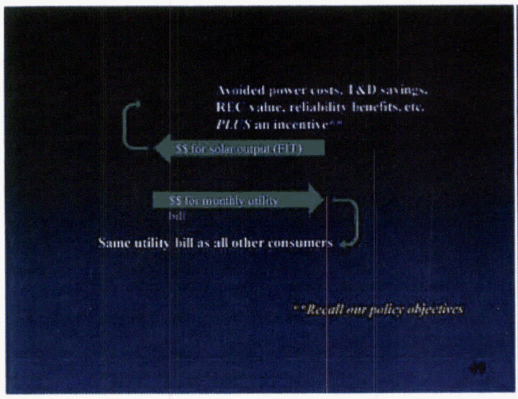
$$\sum MCi * Kwhi \neq \text{Revenue Requirement}$$

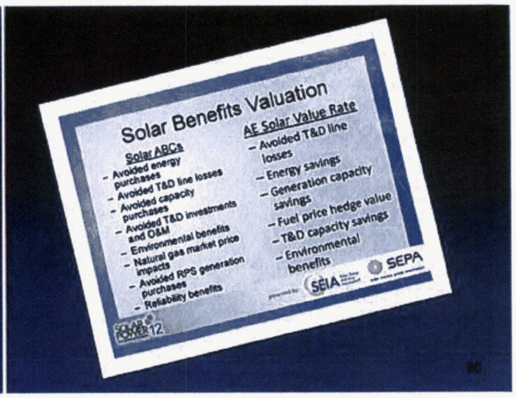
- Thus, rate structures employing MC pricing must usually compromise somewhere.
- Complication arises when customer is both buyer and seller, or has competitive options.
- Complex rate structures are not accepted by consumers, at least in 2012.

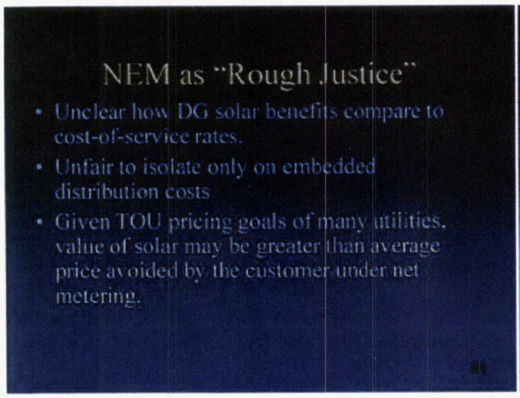


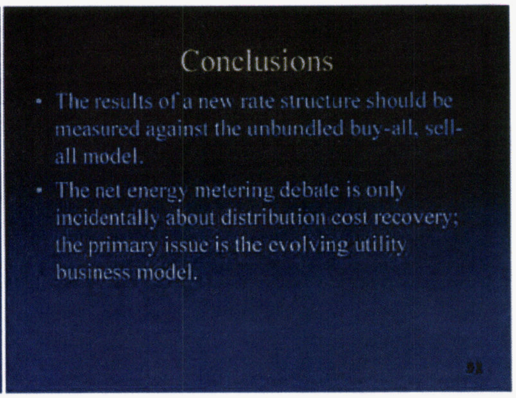

Unbundling the DG-Utility Transaction
To isolate the DG payment from tariffed rates, consider this "buy-all, sell-all" model:
– Utility purchases DG output at full avoided cost price (including T&D effects and others)
– Utility bills customer for all electricity used under tariffed rates
– Separately, the utility pays incentive to promote DG production

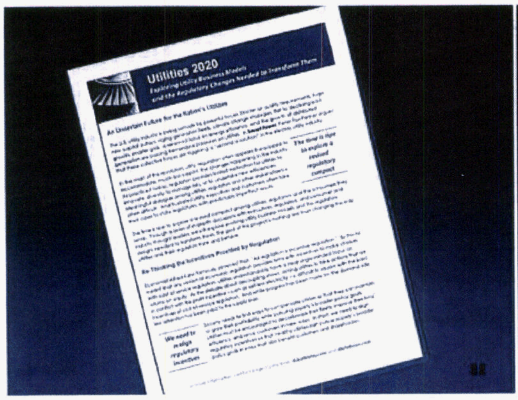

POWERCO
$$ for solar output (FIT)
$$ for monthly utility bill

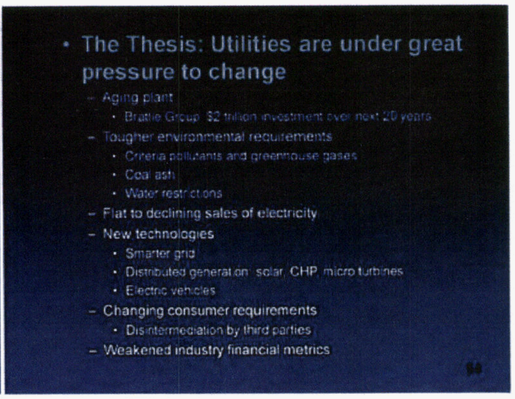

Avoided power costs, T&D savings, REC value, reliability benefits, etc. PLUS an incentive**
$$ for solar output (FIT)
$$ for monthly utility bill
Same utility bill as all other consumers
**Recall our policy objectives

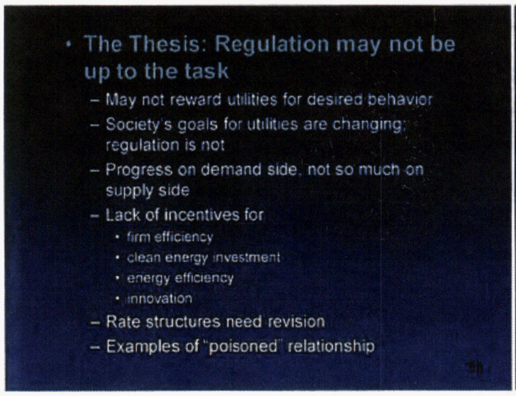

Solar Benefits Valuation
Solar ABCs
- Avoided energy purchases
- Avoided T&D line losses
- Avoided capacity purchases
- Avoided T&D investments and O&M
- Environmental benefits
- Natural gas market price impacts
- Avoided RPS generation purchases
- Reliability benefits
AE Solar Value Rate
– Avoided T&D line losses
– Energy savings
– Generation capacity savings
– Fuel price hedge value
– T&D capacity savings
– Environmental benefits
SEIA
SEPA


NEM as "Rough Justice"
• Unclear how DG solar benefits compare to cost-of-service rates.
• Unfair to isolate only on embedded distribution costs
• Given TOU pricing goals of many utilities, value of solar may be greater than average price avoided by the customer under net metering.

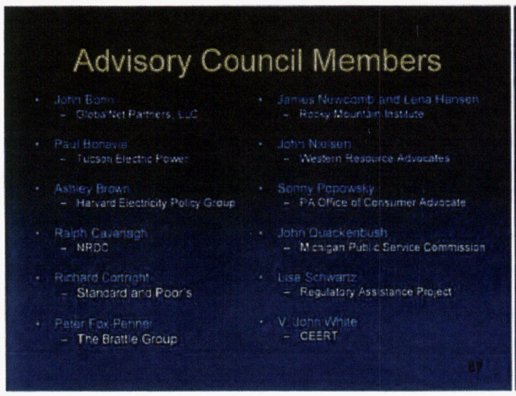

Conclusions
• The results of a new rate structure should be measured against the unbundled buy-all, sell-all model.
• The net energy metering debate is only incidentally about distribution cost recovery; the primary issue is the evolving utility business model.

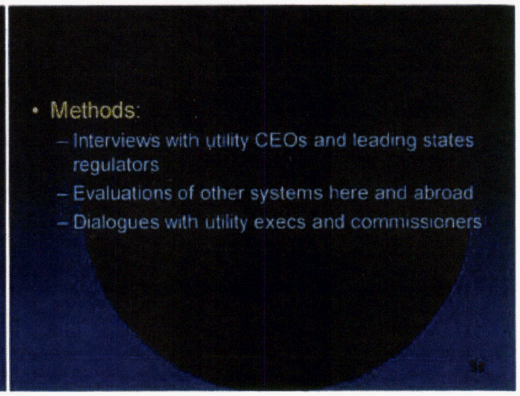

Utilities 2020

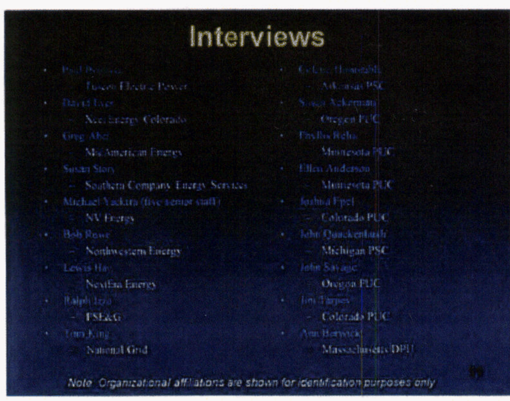

• The Thesis: Utilities are under great pressure to change
– Aging plant
• Brattle Group: $2 trillion investment over next 20 years
– Tougher environmental requirements
• Criteria pollutants and greenhouse gases
• Coal ash
• Water restrictions
– Flat to declining sales of electricity
– New technologies
• Smarter grid
• Distributed generation: solar, CHP, micro turbines
• Electric vehicles
– Changing consumer requirements
• Disintermediation by third parties
– Weakened industry financial metrics

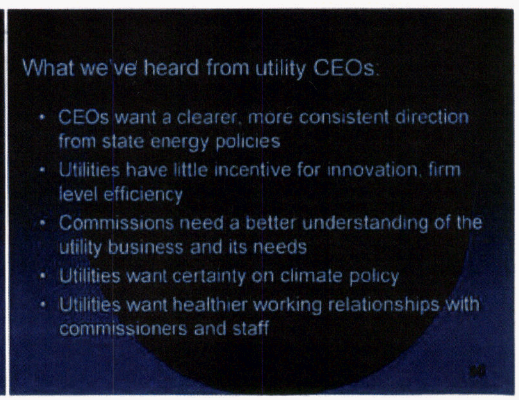

• The Thesis: Regulation may not be up to the task
– May not reward utilities for desired behavior
– Society's goals for utilities are changing; regulation is not
– Progress on demand side, not so much on supply side
– Lack of incentives for
• firm efficiency
• clean energy investment
• energy efficiency
• innovation
– Rate structures need revision
– Examples of "poisoned" relationship

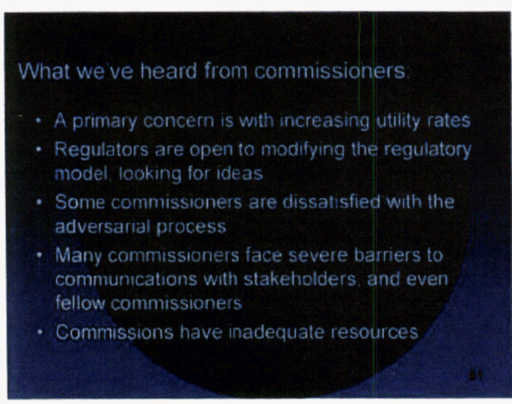

Utilities 2020
• Foundation funded
• Run by two former state regulators named Ron
• Advised by board of experts
• Goal: to explore new business models and advocate new regulatory models to enable new utility business models to evolve.

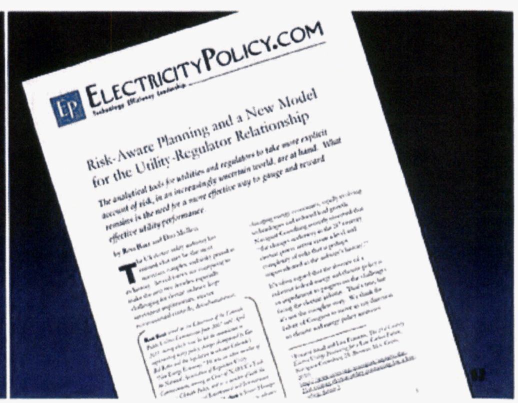

Advisory Council Members
• John Bohn
– GlobalNet Partners, LLC
• Paul Bonavia
– Tucson Electric Power
• Ashley Brown
– Harvard Electricity Policy Group
• Ralph Cavanagh
– NRDC
• Richard Cortright
– Standard and Poor's
• Peter Fox-Penner
– The Brattle Group
• James Newcomb and Lena Hansen
– Rocky Mountain Institute
• John Nielsen
– Western Resource Advocates
• Sonny Popowsky
– PA Office of Consumer Advocate
• John Quackenbush
– Michigan Public Service Commission
• Lisa Schwartz
– Regulatory Assistance Project
• V. John White
– CEERT


• Methods:
– Interviews with utility CEOs and leading states regulators
– Evaluations of other systems here and abroad
– Dialogues with utility execs and commissioners


Interviews
Tucson Electric Power
Xcel Energy Colorado
MidAmerican Energy
Susan Story
Southern Company Energy Services
NV Energy
Northwestern Energy
NextEra Energy
PSE&G
National Grid
Arkansas PSC
Susan Ackerman
Oregon PUC
Phyllis Reha
Minnesota PUC
Ellen Anderson
Minnesota PUC
Joshua Epel
Colorado PUC
John Quackenbush
Michigan PSC
John Savage
Oregon PUC
Colorado PUC
Massachusetts DPU
Note: Organizational affiliations are shown for identification purposes only


What we've heard from utility CEOs:
• CEOs want a clearer, more consistent direction from state energy policies
• Utilities have little incentive for innovation, firm level efficiency
• Commissions need a better understanding of the utility business and its needs
• Utilities want certainty on climate policy
• Utilities want healthier working relationships with commissioners and staff


What we've heard from commissioners:
• A primary concern is with increasing utility rates
• Regulators are open to modifying the regulatory model, looking for ideas
• Some commissioners are dissatisfied with the adversarial process
• Many commissioners face severe barriers to communications with stakeholders, and even fellow commissioners
• Commissions have inadequate resources


ELECTRICITYPOLICY.COM
EP ELECTRICITYPOLICY
Risk-Aware Planning and a New Model for the Utility-Regulator Relationship

Motivations for a new regulatory model

"We need to align regulatory incentives so that healthy utilities can pursue society's broader policy goals in ways that also benefit customers and shareholders."

"Regulation has become confrontational, is often mired in judicial process, and exists amid a charged political setting. It's hard to imagine a worse recipe for managing the transformation of the utility industry."

"A threshold question is whether state utility regulation will evolve to enable the necessary industry changes, or merely follow them, or worst, stand in the way."

Three Potential Regulatory Models

- The UK "RIIO" model
  - Price cap built on RPI-X
  - Output regulation
    - Reliability, Environmental, Innovation, Price, Efficiency, Social Responsibility
- The "Iowa Model"
  - Seventeen years of constant rates, settlements
- The "Grand Bargain"
  - Comprehensive multi-year output-oriented deal
  - Regulator led

Thank You

Ron Binz
Public Policy Consulting
rbinz@rbinz.com

APS Conceptual Solutions

Chuck Miessner, Arizona Public Service

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DE Rate Equity Issues
Potential Solution Concepts

Rate Design Concept

DE generation serves a portion of the customer's load; the utility serves the remaining load at a retail rate that is designed to appropriately recover the cost of service, considering DE's impact on the utility's costs. Excess generation is exported to the grid and may be compensated through some mechanism such as net metering or net billing.

Total DE Export Concept

Total DE generation is exported to the grid and purchased by the utility at a purchase price, which considers DE's impact on the utility's costs. Customer's total electrical load is served by the utility at the retail rate.

Net Metering

Currently APS offers net metering to all customers for up to 125% of their connected load, in accordance with Arizona regulation. Net metering may need to be revised as part of the solution.

Incentives

Incentives could be considered along with the proposed solution.

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Rate Design Concepts

New Solar Rate DE customer is billed under a new retail rate. Charge types more appropriately reflect the cost of service for DE customers - could have a higher basic service charge, demand charge, minimum take kWh charges or other related pricing concepts.

Standby Charges DE customer is billed under current retail rate. Rate rider recovers certain generation, transmission, and/or distribution capacity costs necessary to serve the customer when their solar unit is not running.

Modified Net Metering DE customer is billed under current retail rate. Billed kWh are adjusted (increased) for the solar generation for certain capacity related costs.

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DE Export Concept

Solar Generation: DE customer's total solar generation is exported to the electrical grid and does not directly serve their site load.

Utility purchase: Utility meters the solar generation and purchases it at a specified rate.

Utility supply: Utility serves the DE customer's site load at a retail rate.

Monthly Bill: Utility bills the DE customer for monthly service on the retail rate and credits the bill for the purchased solar energy.

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Next Steps

- New items provided by stakeholders are being posted to www.solarfuturearizona.com as they become available
- Over 24 studies on distributed energy, net metering, and solar energy from around the U.S. have been posted for consideration by workshop participants
- Responses to the stakeholders' data requests have been posted
- Meeting notes from prior workshops have been posted
- Today's presentation has been posted

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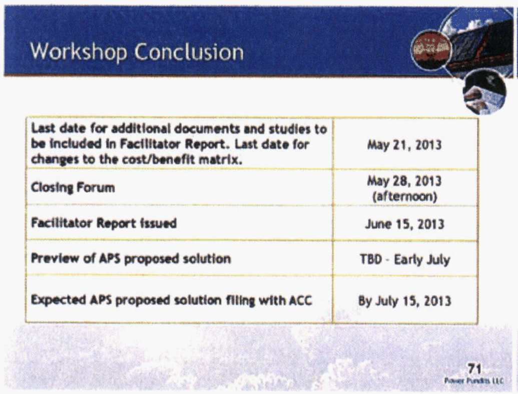
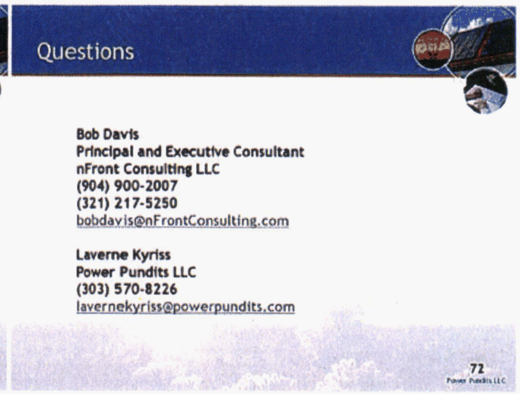


Workshop Conclusion

Last date for additional documents and studies to be included in Facilitator Report. Last date for changes to the cost/benefit matrix.	May 21, 2013
Closing Forum	May 28, 2013 (afternoon)
Facilitator Report issued	June 15, 2013
Preview of APS proposed solution	TBD - Early July
Expected APS proposed solution filing with ACC	By July 15, 2013



Questions

Meeting Notes

POWER PUNDITS LLC.

Decision and Process Advisement in Energy and Water

TO: APS Workshop 4 Participants

FROM: Power Pundits LLC

RE: Workshop 4

DATE: June 4, 2013

As ordered by the Arizona Corporation Commission related to its 2013 Renewable Energy Standard Implementation Plan, Arizona Public Service Company is conducting a multi-session Technical Conference with stakeholders to evaluate the costs and benefits of distributed renewable energy and net metering. The sessions are designed to bring together stakeholders holding a wide range of perspectives, experiences, and levels of technical knowledge to evaluate these costs for all customers—both those who have access to distributed energy and those who do not. Sessions are exploring such issues as environmental mandates, changes in generation requirements resulting from adding distributed energy to the generation stack, localized grid impacts, system losses and other relevant topics. APS engaged a team from Power Pundits LLC to lead, moderate, and manage this technical conference.
Meetings in this series to date have included:

- An opening forum, February 21
- A technical workshop on understanding rates and distributed energy (DE) benefits, March 7
- A follow-up stakeholder call March 14
- A second technical workshop on resource planning and distributed energy costs, March 20
- A third workshop to review the SAIC refresh work and discuss other models to valuing distributed resources, April 25
- This fourth workshop, documented here, held May 9 at the APS Learning Center in downtown Phoenix

Workshop 4 focused on policy and valuation perspectives. The agenda included a discussion of a draft cost-benefit matrix for distributed energy, two views on how to appropriately value solar energy in the Southwest, a presentation outlining several policy and legislative considerations for solar distributed energy and a first look at conceptual solutions from APS.

Fifty-four stakeholders registered for this forum, including 13 people who participated via a conference phone connection. More than 50 attended in person. Copies of the agenda and presentation slides are available at www.solarfuturearizona.com. An audio recording of the workshop is also available on the site. These notes are the reflection of Power Pundits staff who participated in the workshop and are not a verbatim record. We believe they accurately reflect the sense of the day's meeting.

➢ In these meeting notes, action items are indicated by an arrow before the item. Questions from participants are in **bold type**. Answers are *italicized.*

Welcome and Workshop Overview (SLIDES 1-6)
Bob Davis from nFront Consulting welcomed workshop participants to this fourth workshop in the multi-session APS Technical Conference on distributed energy and net metering. He briefly reminded participants of the conference purpose, workshop goals and where we are in the process, and highlighted today's agenda.

Cost-Benefit Matrix (See the draft Matrix on the www.solarfuturearizona.com Website)
Bob Davis next discussed the matrix (provided as a handout) that currently shows four perspectives on the costs and benefits of solar distributed energy. So far, AECC representing large commercial customers, APS, Western Resources Advocates representing an environmental perspective, and Jamie Kerr, representing solar stakeholders, have contributed to this matrix.

Chuck Miessner from APS discussed the utility's perspective on the various categories on the matrix. Mr. Miessner noted that several of the categories on the draft matrix are external to the costs allowed in the utility rate-making process, explaining that while these are important they are not part of APS' consideration of the net impacts of DE. He said APS focused on the costs and benefits that are measureable and the time frame for valuing these costs. Mr. Miessner explained that there are two aspects to these values: the long-term resource planning perspective and the second is how the costs and benefits inform APS's ongoing rate-making process to recover costs.

Gary Mirich, Arizonans for Electric Choice and Competition, summarized his association's comments outlining their view that the draft matrix focused on the benefits of solar DE. Added their concerns and requirements for costs to be identified and cost shifting.

Jamie Kern added that there is a need to include the ratepayer perspective in the mix. He suggested adding decommissioning costs and ratepayer interests, including low-cost and DG. Mr. Kern referred participants to the various studies that are posted on the solarfuturearizona.com Website that capture these perspectives.

Mr. Davis noted that David Berry, Western Resources Advocates, generally agreed with solar stakeholder perspectives and also suggested the need to identify solar program participants' costs and benefits and how that affects the entire program. He explained that the solar stakeholders' perspective currently summarized on the draft matrix is the facilitator's understanding of that view. He encouraged participants to work with their representatives on the workgroup or to join the discussion and add their own thoughts.

He outlined the four categories that were added as a result of this review by workshop participants. These are: decommissioning costs of assets including solar DE assets; ratepayer and consumer interests; ratepayer cross subsidization; and utility system costs including ancillary services, integration costs, and system costs to manage DE asset use on the grid.

Qs and As
Q: Where do I see the whole category of distributed generation in total? CHP, etc. are we here to promote it? I don't see that on the list.
I wouldn't want to turn the matrix into a philosophical discussion. I encourage participants to consider adding a column for other perspectives, solar water heating, etc.
Q: Adding the ratepayer cross subsidization category is essentially making a one-sided statement on the outcome of this technical conference. I don't think this is fair inclusion when the purpose is to determine the costs and benefits of DE. We need to look at both sides.

Right now, we've only had input from one perspective. Please review the definition. I've tried to structure it to include increases or decreases. Please provide your comments. I encourage other stakeholders to add your perspectives. I agree that this is the crux of why we are here.
Q: Economic development impacts? Small incentives for DE and solar water heating?
Econ development is on the list.
Q: Schools have a different load profile than residential DE and have a significant investment in DE. We have a benefit to high end of demand curve, reducing our demand in the late afternoon and weekend. Our benefit to the system isn't fully recognized and our costs are exaggerated. We've worked with APS to address this in rates, but this process is likely to change that.
We welcome you to participate by offering your perspective to the matrix.

Stakeholder perspectives

- Including ratepayer and consumer interests is important but these interests often go beyond the ability to enumerate a value and these need to be a part of the equation.
- ➢ The deadline for comments on the cost benefit matrix is May 21 to Bob Davis.

Benefits and Costs of Solar DG for APS (SLIDES 7-23)
Tom Beach, Crossborder Energy, presented the results of his recent work to analyze the costs and benefits of solar distributed generation in the APS service territory. His goal was to understand how demand-side solar will impact APS ratepayers. His work was done on behalf of the Solar Energy Industries Association as their contribution to this conference. Mr. Beach said the logical test to begin with is the RIM or Ratepayer Impact Test because it's stringent and is often called the "no losers" test. Mr. Beach noted that many states in evaluating demand side resources however use a societal or total resource cost test. He explained that if the resource passes this total cost test, it's good for society and it's OK for rates to go up adding that participants benefit because even if their rates go up, their bills go down because their usage goes down.

Mr. Beach noted that this study did not focus solely on net metering, differing from the work he did in California which focused only on the power export to the grid. For AZ, he looked at both the exports and the energy efficiency of solar DG used onsite by the customer. He added that looking at net metering only in this study would have been more complex, requiring an examination of hourly loads and avoided costs.

Mr. Beach explained that since solar DG is a long-term resource, he used a 20-year time horizon. He suggested that it's important to recognize some of the DG benefits including short lead-time and scalability and that DG resources don't need to include all the characteristics of a 400 MW or 100 MW utility-scale resource. He noted that according to APS' 2012 IRP, about 1,150 MW of demand side resources will be coming online before 2017, deferring the need for additional resource before that date. He used data from 2012 IRP, the previous Beck study and the current SAIC work as well as some data from regional energy markets.

In examining the costs and benefits, Mr. Beach looked at the long-term resources that would be deferred or avoided by DG. For APS, this is combustion turbine and combined cycle plants. For this assessment, the most important input is natural gas prices, he said. He used current forward market prices from April 2013 to project gas prices out to 2033, explaining that his results are basically identical to SAIC's work and are significantly lower than the forecasts used in the 2012 IRP (slide 11).

For the peak months of June-Sep, he used costs for a new CT as the avoided energy costs (slide 12). He produced a low, base and high case to accommodate differences in greenhouse gas costs assumptions. For off-peak months, Mr. Beach did use a combined cycle plant (slide 13). He said that in the short term, this is consistent with Palo Verde forward prices. Using these avoided energy curves and pricing them out over 20 years at a discount rate of 7.21 percent (APS' weighted average cost of capital) is shown on slide 14.

The approach to estimating capacity benefits is shown on slide 15. A 50 percent capacity value was used for solar DG resulting in an avoided capacity value of 6.7 cents per kWh. For transmission benefits, Mr. Beach said it's important to remember to not assume the lumpiness of traditional resources. He said two-thirds of DG power serves the customers load and never tough the grid. The rest is consumed almost immediately by the DG customer's neighbors. He noted that this definitely reduces loading on the transmission system and avoids, over the long run, transmission costs, resulting in a transmission benefit of about 2.1 cents per kWh. He explained that distribution benefits are similarly calculated but this is a more complicated situation. He said SAIC showed 5 to 9 projects that might reduce loading on a feeder. He used a number from the Beck study (page 3-26). He said they found that about 50 percent of the distribution feeders would have avoided costs from adding solar DG. He suggested the ELCC calculation may not be accurate because distribution feeder peak is not correlated to system peak noting that the result is small—a benefit of 0.2 cents per kWh.

Mr. Beach said WECC requires utilities to maintain 7 percent reserves of their thermal resources for ancillary service and capacity reserve benefits (slide 16). He added that most utilities maintain a 15-percent reserve margin, resulting in 15 percent of the avoided generation cost. He said, the ancillary services benefit is based on a CAISO study showing that ancillary services cost 7 percent of avoided energy costs.

Mr. Beach said environmental benefits include reduction in criteria pollution and in water use. He explained that the values are from the 2012 IRP. He said avoided renewable benefits (slide 20) is a catch-all category including use of private capital, meeting or exceeding RES requirements, diversifying resource mix and other hard to quantify benefits. He explained that price mitigation is the resulting downward pressure on both natural gas and electricity prices from having renewable on the grid, noting that Lawrence Berkley Laboratory estimated this value at $7 to $20 per MWh.

Mr. Beach said grid security reflects that small distributed installations are not likely to all fail at once, comparing the San Onefre situation in which the 15-month outage so far is costing California consumers $1 billion in replacement power. He said he also included employment benefits here. He noted that it may be a valid criticism that this is not a direct ratepayer benefit. He included it because policy makers care and because studies have shown that renewable distributed energy systems contributed to more local employment than utility scale systems. Mr. Beach noted that Hoff's study of NJ and PA valued these benefits at $100 to $140 per MWh. He calculated this benefit for APS on the differential of the revenue requirements in the 2012 IRP between the enhanced renewable portfolio and the base case portfolio. He said that difference is about 4.5 cents per kWh, suggesting that this serves as a proxy for the benefits you get from adding DG.

Mr. Beach next discussed the cost side (slide 21), stating that the principal costs are the lost revenues from customers self-providing. He took this data from a data request response provided by APS. The low numbers for DG incentives he said are because he understands AZ is phasing out incentives and has already phased some out. Integration costs are based on APS solar integration study, he noted.

Mr. Beach summarized that total benefits add to 21.5 cents to 23.7 cents per kWh and costs add to 13.9 cents to 15.5 cents per kWh, resulting in a cost-benefit ratio of 1.7 to 1.5. He said benefits exceed costs in both residential and business markets both individually and combined. He said net benefits are based on the SAIC projection for 2015 of incremental solar of 431,000 MWh at $79 per MWh, or $34 million per year in net benefits in 2015.

Mr. Beach reflected that he's now done these studies in seven states. He has found the benefits are remarkably consistent because gas-fired resources tend to be on the margin in all of these states. The differences are on the cost side, he said, because of different rate designs. He said Idaho has a lot of coal and hydro so the cost side is very low; California, conversely has no coal, lots of natural gas and renewable and lots of efficiency. He explained that California comes out much closer to a 1.0 on the ratio and Arizona, Colorado and New Mexico come out somewhere in the middle.

Mr. Beach noted that there was one significant cost on the avoided energy side not included in this study. APS provided some information on its hedging costs. He said these are about $50 million per year for 50 bcf of gas, or about $1 per million BTUs. He said this would increase the gas forecast by about 20 percent. He noted that there certainly is an argument that is a real cost of doing business and should be included.

Mr. Beach followed up with some comments on the "duck" graph. He said he thinks the CAISO is backing away from that metric, explaining that their original assumption was that the solar was going to be single axis trackers. Trackers fall off steeply at the end of the day. He said this is not a realistic assumption because the ramp rate is a lot less steep. Mr. Beach said the graph is of an average day in March—the absolute low demand day in CA when gas plants are off for maintenance. He said the size of that ramp is not something that can't be handled in CA, especially if maintenance schedules are changed accordingly. He also noted that another consideration for the cause of the steep ramp is that in March the sun is setting when people are returning home from work. Solar is dropping off and load is ramping up to the evening peak in March. He said this is 100 percent predictable and system planners can prepare for this.

Qs and As

Q: Even though it's more complex, it's probably more germane to look at the net metering export only. We're not looking at changing rate structures for encourage energy efficiency.
That's true and that's why some utilities do not use the RIM test for DG.

Q: I thought that SDG&E had considered this approach and the CA PUC said to only focus on the net metering export piece? I think there's a ruling on this.
No it's just the opposite. There's a new CA net metering study. The first net metering study from the CPUC focused only on exports but the legislature wanted to see the results for onsite use as well. So now we're going to see both pieces. While for this study we didn't examine it, it's likely that under an exports-only analysis, since the power exports occur in the middle of the afternoon, the value for that power per kWh is likely to be higher than the entire output. You'd expect to get a higher cost-benefit ratio under an exports-only scenario that what we came up with here.

Q: Was there a reason for the 20-year time horizon vs. the 25-year typical warranty for a PV module?
The main reason for 20 years was to minimize the need to extend some available data. You could do a 25-year time horizon.

Q: On slide 12, in determining the avoided energy costs for peak months, did you use a simplified assumption or some kind of hourly dispatch to replicate APS' system?
No it was not based on ProMod modeling.

Q: Because of the low-load factor characteristics of APS' system, the CTs are only run a few hours a day in the summer. The capacity factors are de minimis compared to a CT's capacity factor. The CT heat rate is 6,900 or 7,000 BTU/kWh and this is 30 percent higher. APS uses a dispatch model and we get different results.
You can see I plotted the SAIC results. Dispatch models are powerful tools but they don't promote consensus. They are confidential and opaque. In open deregulated markets with LMP pricing the use of production cost modeling is not very prevalent because you can use market data. For instance the Palo Verde forward price could be considered. APS could very well generate power at less than that cost, but the avoided energy cost is still the Palo Verde price because that's your opportunity cost for making sales.
Q: Your using the on-peak production heat rate of the Palo Verde forward as the production profile for many hours—the solar profile beginning at 7 am each day. The hourly market is very different. The ProMod model is the industry standard. This is very different than the actual avoided energy on the APS system.
ProMod may be the standard where you don't have visible energy markets. The Palo Verde forward is a price for a 16-hour block when PV is producing. It also includes hours in the morning and evening which may be less valuable than the mid-day PV power. This is an area for potential further discussion.
Q: In calculating the energy benefits shown on slide 14, did you calculate values at 2015, 2020 and 2025? Did you look at individual tranches or use a levelized number?
It includes those years but is a levelized number. The approach taken is to consider the value of solar today and for the next several years, not to look at specific years. One of the reasons APS doesn't need capacity until 2017 is because the demand-side resources are being installed between now and then.
Q: On slide 15, you're using APS data. Do the capital costs include transmission?
Yes, I believe there are some generation-related transmission costs included.
Q: On slide 15, you're showing 50 percent capacity value. This is full capacity value for a fixed position array. Do you account for several years in which APS doesn't need capacity? Do you discount your capacity factor value in any way? Do you account for the diminishing return for higher or medium penetration scenarios?
The answer is no and no. This gets back to the short lead time scale of DG. It would be possible to not reflect any capacity value until 2017 but the APS resource plan assumes 1,150 MW of DG between now and then. If you took those out the year of need would be much closer to the present. In regard to the diminishing return aspect, this study is looking at the value of solar in 2013, not at the value in 2020 or 2025 when more solar is likely to be installed. The data is available in the SAIC study. Conceptually they are accurate. If you add a bunch of solar to the APS system, you will shift the peak. You can do an ELCC calculation that shows the value of solar decreases. It seems like that's getting ahead of ourselves. It assumes that solar's going to be so successful that it will have no value in the future. In Germany they have almost 30 GWs on a system that's about twice the size of CA. We have seen the peak shift, we have seen decreased values in mid-afternoon but it's also resulted in significant benefits in terms of lower wholesale prices in Germany. Trying to predict the value of solar in 2020 or 2025 is something we should do in five years when we know how much solar has been added to date. I don't believe that trying to estimate the future value helps us determine what we should do today.
Q: On slide 13, considering Palo Verde forwards, APS has tariffs for net metering. For excess generation over 100 percent offset, they value the wholesale buyback at the average annual market price which is the daily on-peak market price from May 1 to April 30 of the current year. Prices are taken from the daily firm on-peak price at Palo Verde as reported by Dow Jones. Is that the same resource that you're using?
Yes.

Q: On slide 15, you are showing a production factor of 1,575 kWh per kW. I'm assuming there can be different values in the residential sector. This would be a very low value on the commercial side. I would assume that this would increase the capacity value of solar through a higher production value.

That value goes into the denominator of this calculation. More production reduces this value. For trackers, you offset this by assuming a higher ELCC. For a commercial system that is a better producer, you have a 70 percent ELCC. You account for increased production in this way.

Q: In considering this production factor on slide 15, for residential installations 1,500 is a low number and 1,700 is low for commercial systems. So when you combine these, how can 1,575 be the correct value?

I got this from the SAIC presentation. I wasn't trying to reinvent their data. If 1,600 is more accurate, it would make a small change in the calculation.

Q: On slide 16, regarding ancillary services, utilities, such as APS, that belong to a reserve sharing pool have a requirement that is about half of what you're showing. The way APS calculates the ELCC for distributed resources includes this so I don't think it's appropriate to take this additional 15 percent value.

The perspective here is that DG reduces the load on your system and so you need to acquire capacity to meet that load plus 15 percent. A customer meeting its own demand with DG reduces the utility's capacity requirement by 115 percent of that demand.

Q: If the new net metering rule provides a payment of 10 cents/kWh and the benefit was 8 cents, the delta is 2 cents or 20 percent. There's a 2-cent value to the utility because they're selling that power to the DG customer's neighbor. Does your model address this?

People often ask if a net metering customer receives services from the grid for which the utility is not getting compensated. My answer is that the utility is being compensated and here's why. When the net metering customer's meter is running forward—such as at night—the customer is paying the full retail rate, including the T&D system costs.

Q: Going forward, if there's a delta in what the utility is compensating a DG customer and the value they provide, does your model address this? The utility is charging the neighbor the full 10-cent rate, but not incurring 20 percent of the expenses to create that DG system.

When the power is consumed by the DG customer's neighbors, the utility has savings because they don't have to invest in T&D because the power is flowing 100 feet and not 100 miles. That's what we're measuring in terms of transmission benefits.

Q: This is a common misperception. To use your example, APS is paying 8 cents for net metering and charging the neighboring customer 10 cents for that energy. APS is charging 10 cents retail rate for all of its services, for home hookup, substation, primary and secondary lines, transmission lines, back-up power capacity. Just because a net metering customer is supplying some energy, you're not supplying all of these other services. If we were disconnecting your neighbor from the APS system and you were supplying all of his needs, you would have a point, but that's not the situation here. You're not providing full utility service to your neighbor. You're providing some energy and some short-term service. The other services are being supplied by APS and the utility should be able to recover the costs of those services.

This is a long-term analysis. Some of your customers are producing their own power and serving their own load. This does allow APS to avoid some cost. APS' resource plan shows energy efficiency and demand response resources to avoid building more transmission lines and generating plants. This is no different.

Q: APS was going to calculate the export percentage for all of its net metering customers. Has that been completed? Does APS have an idea of how much energy is exported compared to what is consumed onsite?

Chuck Miessner from APS said he didn't have that data in front of him. It was provided in response to one of the data requests.

- *[This is available on the solarfuturearizona.com Website.]*

Q: On slide 15, regarding transmission benefits, the result is 2.1 cents per kWh. SAIC's report showed the benefit to be less than 0.5 cents per kWh. The SAIC study did not show transmission costs savings of $145 million. So why did you go back to the Beck study? It wasn't that the SAIC study didn't calculate this value. It said it was zero cost avoided.

The Beck data was the available number by which transmission costs decrease at peak demand. The SAIC study showed no load-growth related deferrable projects.

Q: Considering costs for DG incentives (slide 21), many of the current systems get the old, higher value incentives. Shouldn't those costs be included here?

Possibly. I guess I'd need to be shown what's in the resource plan for future near term (2014-2016) compared to what's already installed. We should be clear, this is a cost to ratepayers, not APS.

Q: Rebates are a separate tariff and shouldn't have anything to do with rate design?

We're looking at costs to ratepayers and I'm assuming ratepayers are funding those incentives. I do think they should be included as a cost.

Q: It seems to me you're looking at marginal costs when we're looking at new generation. Consideration of sunk costs or decisions on past incentives is irrelevant. It's all about marginal costs going forward.

Because there are sunk incentive costs going forward, I thought I should show a range.

Q: I'm confused about where this 19.7 cents [lost retail rate revenues on slide 21] comes from compared to the tariffs. In Workshop 1, we saw a handout showing APS variable costs to be 31 percent for residential service. You're losing revenue but this doesn't add up in my mind. If 69 percent of your costs are fixed, how is this affecting the bottom line? You have these costs regardless?

I think APS has a 15 ½ cent residential rate. This is escalated for 20 years and then levelized. That's why it's higher than the current residential rate. This is looking at the revenue APS is losing from DG customers getting a full retail rate credit for serving their own load.

Q: Do you have a summary of the number you just shared [in your concluding remarks on cost-benefit ratios]?

I have not compiled all of my studies across various states. I'll talk to my client about that.

Q: This is a long-range study. My question to APS is, what is your view of this study? Does it have legitimacy? Do we go forward and use this kind of cost-benefit analysis? Do you agree, disagree and how much? Trying to reach a common ground is very important.

Q: I see APS is going to present solutions to a study we just saw? What does that mean?

Chuck Miessner, from APS, reported that APS does not have a solution today, APS is still in the "homework" stage, listening to all the materials in the workshop as well as other things that are happening around the country. APS thought it would be appropriate to discuss some of the concepts we see. We recognize that there are going to be differences in numbers and approaches. APS is on track to present its solution this summer to the ACC.

Q: Does the conclusion that there is a net benefit, in theory if these numbers are correct, that APS should pay a small premium for net metering?

Yes. You could raise the incentives and still benefit other ratepayers.

Q: Going back to slide 22, I still struggle with a methodology issue. Concerning the capacity benefit from centrally dispatched resources, with solar PV, I just don't buy that we're avoiding these costs. If I knew that they didn't need service during the summer peak, then I would agree. But that's not the reality. Solar PV customers aren't going to say, "I'm going to go off-grid. I don't need capacity." There are times during the day when there are clouds or monsoons. It can be 20 minutes or 10 seconds. But they want the grid when they need that power. I struggle with the proposal that the generation and transmission capacity costs are truly avoided. The accumulation of DG does have some benefit. But when we come down to the

rate design, I don't think that we're avoiding those peakers. I question the methodology of including the fixed capacity costs.
We're not talking about customers separating from the grid or getting rid of APS. We're talking about the utility having to build fewer resources than they would otherwise.
Q: How does the utility assure it has enough capacity when these customers are still connected to the grid and their resource isn't dispatchable?
Anytime there's a new technology there's a doubt it will work. Not all 100,000 PV systems in CA will fail at a single time. Utilities will become pretty good at determining customer demand as new technologies and new approaches, such as price signals, evolve. It's nothing that the utility hasn't dealt with in the past and can't deal with in the future. It's just a different way of forecasting demand.
Q: On the issue of energy avoided, Tom's model uses costs for CTs. APS modeling reports that it's 30 percent coal, 50 percent combined cycle and the rest CT. If we accept these energy displacements, would you look at the capacity costs of coal, CCT and CT in these same proportions? Isn't there's a relationship between the capacity avoided and the energy avoided.
Yes. That's a matter of debate. Some places look at just the cost of the avoided resource. Other places look at the system running cost and add on a capacity value. If the deferrable resource were a coal plant, you definitely would look at the capacity cost.

Stakeholder perspectives

- I'd like to point out a difference between the Palo Verde market and the price of power from the production cost model and the power produced by DG. The Palo Verde price is for a firm product that doesn't vary hour to hour. That's another big difference.
- Q: From a resource planning perspective, APS has costs as well as a profit factor built into its revenue requirement. From the DG perspective, this allocation should be shifted because you aren't incurring all of those costs.
- APS has looked at the resource plan and looked at higher penetrations look like. Tom said that it's going to be a different way of managing the system. When you have that trough in the middle of the day with non-dispatchable resources. The CAISO has a chart—the "duck" chart. We have our own. You ramp up in the morning with natural gas. You've got a huge trough in the middle of the day with high solar production and when the sun sets, you've got a huge peak. You need the infrastructure to serve that load. What we're seeing on our system is very different. I don't know in my own mind what we'll need so that we can start and stop units multiple times per day. Combined cycle units won't do that. CA will experience it much sooner and we'll try to learn from them.
- I believe the pipeline reservation charge is significantly higher by a factor of 2 to 3 than APS incurs.
- I think what you've heard today is that APS has some questions about the Value of Solar model. It's very new to APS. We go back to some of the basic building blocks. Those aren't new. The methodology is new. Some simplifying assumptions such as the treatment of CTs for avoided energy. That's not avoided energy. It's a different number. I don't want to criticize, but we don't agree on the numerical value today. We do have some issues with how some of the avoided costs are calculated.
- Chuck Miessner, APS, said the focus of his talk today will be on concepts. He's not going to be resolving numbers.
- APS has its own duck chart and it has been publically presented. The situation will be more severe in the springtime than in the summer. APS has a dual peak in the winter. We expect this to extend from Oct to April. Yes the sunset is predictable. And yes we know we'll have to build natural gas plants to deal with this.
- By 2025, you may have some significant storage technologies that may be game changers as well.

Sustainable Solar Adoption (Slides 25-39)

Chris Yunker, SDG&E, provided a presentation on creating a sustainable solar market structure. He said his subject is a very different issue than the last presentation. He noted that making a policy decision doesn't help determine how to implement that policy. CA is looking all distributed energy, he said and SDG&E is also looking at net zero energy production. He explained that whatever choices SDG&E makes, they have to find a way to transition to that goal.

Mr. Yunker likened their approach to that of an iPhone, because the iPhone created a platform for customization. He said that's the market structure SDG&E's working to emulate—DG, EV, distributed storage, selling service to the grid, community solar, green tariffs, service from an ESP or traditional utility procurement service. He said the utility needs to consider what to do if it has 100 percent net zero customers, resulting in zero dollars of revenue collection. That's unsustainable, he said, asking, do they not need the grid? He said SDG&E needs to find a way in advance to address that. Unfortunately, he said, the utility faces many vested interests and that's creating significant challenges. He explained that CA utilities have an RPS target of 33 percent by 2020 but noted that his utility may reach this goal by 2015. SDG&E's approach has been to consider previous analysis and looked at a cost of service approach he said, noting the utility needs both a rate structure and a market design that can accommodate this going forward.

For SDG&E, peak matches up relatively well with solar (slide 31). However, the peak will shift, he said and the utility needs to match up price signals to accommodate this shift to incent people to meet this change. Today, he said, instead of following load they're following capacity needs. He said utility staff must ask, "What's the biggest need for flexible capacity? Have we built a system to incentivize the need for flexible capacity?" He said utilities need a market structure that follows these costs. Mr. Yunker said whenever the capacity needs shift, the correct price signal will be sent and the market can respond. He noted that some people won't want to deal with this and will pay a higher price. Others will adopt new technology, such as batteries, that will allow them to shift their energy use away from peak times.

He explained that in February, SDG&E has low load and now has increased solar penetration. Utility staff are asking, "Are we sending a correct price signal that incents the correct market structure?" Today, at 20 percent penetration, the utility sometimes have more generation than needed and is selling at a loss. He said they are looking at the drivers for their infrastructure requirements and what they will be. Now they're thinking about net capacity need. Instead of matching and balancing the intermittent renewable, he said they need to send a price signal to minimize the most expensive resource. Going into the spring high production months for wind and solar, he said they need to think about incentivizing EV customers who are charging in the middle of the night to charge in the middle of the day. He said they need to send the price signal to manage load and have the correct market structure in place to do so.

Now also, SDG&E needs to move down to the individual customer and the individual feeder to have the necessary infrastructure in place to operate the system in new ways. In CA, even though the system peak is at 4 pm, Mr. Yunker said the distribution capacity peak is at 7 or 8 pm. He asked, "Are we sending the correct price signal to shift the load at that time?" He said SDG&E has some experimental EV rates, with some EV customers having a standard rate, others having a super off-peak TOU rate. These customers charge between midnight and 5 am, he explained. The others come home and create more demand at our peak cost time, creating more costs for everyone, he said.

Mr. Yunker made a point on diversity of intermittent resources, noting SDG&E's study data on intermittency shows inconsistency. On some days all is fine, he said. On others, the utility needs to provide back-up capacity. He said they may or may not offset each other due to geographic diversity.

He again said the question to ask is, "Are we providing the right price signals to address this need?" He said there's a business opportunity for providing the batteries to back this up. He noted, some will decide to just pay the utility for this capacity and others will adopt the new technology and avoid the cost. He said it's important to promote multiple technologies and not just one. Mr. Yunker said we can never predict the future and never keep up with technology. He said technology will always move faster than we can. He said their goal at SDG&E is to set up the market structure so people don't get surprised. For instance, he said, if you've set it up so people only produce energy and not reactive power, that's what you'll get. For a while the utility can handle it. But you'll get to a point where the voltage swings are outside of the compliance range, lights are flickering and people are starting to complain about their computers getting fried. It's a problem to introduce a market penalty at this point. He suggested that the utility could have solved this problem early on by sending a price signal for reactive power, and installing smart inverters.
Not sending the right price signals exacerbates the utility's challenges, he said, leading to unbundling costs and services to incentive the right behavior. He suggested that if there's a need for reactive power, send the right price signal and see if the market responds. Either the market or the utility can respond as long as you charge accordingly.

Mr. Yunker explained that SDG&E has moved to a cost-of-service approach by identifying the costs of individual services. He said that with a bundled rate design, there's no way to balance the different needs and keep everyone whole. He said utilities have to unbundle pricing to match what technology has unbundled. If the customer has the ability to unbundle their services and the utility hasn't unbundled prices, he said it will end up incentivizing counterproductive behavior and create cost shifts among customers. He said for customers who want simplicity, the utility can offer flat rates, noting this requires a hedge built into the flat rate. For customers who want more dynamic control, he suggested offering TOU, dynamic pricing for critical peak times. He said if someone wants to self-supply their own energy, the utility still has distribution and reliability costs for those services that can be billed separately from the energy services.

Mr. Yunker came back to a key point of the cost of service approach, noting: When a customer receives a service, they should pay for it. When they provide a service, they should be compensated for it. He said utilities need to be forward thinking about what new services customers may need as they adopt new technology. He noted that it's important to remember that the utility time scales and the regulatory time frames are slow process. He believes it's better to be proactive than reactive.

He said the main point is that accurate pricing must have nothing to do with the level of subsidy provided to meet a policy goal. If a subsidy is required to meet a policy goal, he said, the utility should look at the market solution and then fill the gap with a subsidy. He suggested doing this in a transparent incentive outside of the rate design structure. He said this provides for customers to continue to receive the right price signals and they make the right decisions. He added that this also allows the utility to right-size the incentive to achieve its policy goal at minimum cost. Mr. Yunker said that incentives buried in rate design don't follow market pricing and make it difficult to determine the correct incentives. He said this makes it difficult to recover these costs from all customers and to equitably recover costs across all customer classes without cross subsidization.

He said the issue is not which policy goals should be approved; it's not a program or technology choice. He said the issue is what is the market design and structure that will support options for various policy choices? He added that California's residential rate OIR, setting forth 10 principles for evaluating optimal rate design (Nov 11, 2012) is congruent with this approach.

Qs and As

Q: Looking at the 2020 peak day, isn't the peak lowered by the DG and not by the central station service? The load is still the same.
No, before it was just load. We didn't have renewables, only firm capacity. We had baseload resources that could be on all the time. Then we added resources with capacity factors of up to 50 percent, CCTs and CTs. These were more expensive but prices were following load—dispatching the cheapest resources first.

Q: Can you comment in studies you've seen about how customers respond to TOU vs. peak demand price signals?
It varies depending on the specific program, In general, the more simple and automated that you can make it for customers, the easier it is for them to respond. For EVs, it's very easy, the timers are there and they just have to set it. If you don't send them price signals, they don't buy a timer. When you look at dynamic pricing, it depends on how you set it up. On the stick side, if you load the costs on the few hours of peak, customers reduce load to avoid these times or they pay a hefty charge. On the carrot side, you can get a variety of responses, depending on program design. In CA, we've seen Peak Time Rebate where everyone was defaulted to this. Customers who signed up for alerts responded well. Default customers, however, were statistically insignificant.

Q: How far along is SDG&E on smart meter installations so customers can know about peak demand times?
We're almost 100 percent deployed. Customers can get Green Button so they can get their energy use. We're still working on this, but that gets to the transition period. Do you wait until it's happening or do you get out ahead of it? Do you put in place the tools, structure and price signals so the customers can make choices?

Q: I just noticed that Germany is creating an incentive for storage. This seems to be a good example of what you are advocating.
We're learning from them. We believe we have to incentivize for all policy goals and technologies.

Q: I think the argument isn't what to do at 100 percent, but how to accommodate the benefit from providing DG?
Why not provide a direct incentive. Consider the California Solar Incentive. We could have planned the benefit at the outset and created certainty for the customers. Instead, they don't know if the rate is going to change and if the benefit will be eliminated.

Q: Since things are always changing, how can we set something up today when the problem isn't here yet? We could have policy and technology changes that supersede the solution?
I'm not suggesting picking a technology or solution. I'm saying unbundle both the prices and the services. That approach will allow you the flexibility to adapt to the changes that will come. Make "no regrets" decisions that are resilient regardless of the outcome.

Q: One aspect of your construct that is troubling for me is establishing the utility's avoided cost and then providing an incentive above that cost. Short-term incentives won't support that market change. Incentives tend to be doled out in political vs. economic processes. How do you make sure these are set at the right level?
That's the point that transparent methods are more effective. There is no easy solution. When you do it with rate design it's more difficult and more opaque. If you create incentives using rates, you're automatically creating biases.

Q: There's a downside if your rate design is too complex for customers to understand.
That's why I'm suggesting that you can offer a flat rate approach to accommodate customer choice. This just requires a hedge that these customers pay for.

The Evolution of Net Metering and Rate Design and the Utility Business Model (Slides 41-65)
Ron Binz, Public Policy Consulting and former CO PUC chair, provided a presentation on policy and legislative considerations on solar DE.

Mr. Binz said he hoped to bring an understanding that the problem participants in this conference are trying to solve is a lot bigger than the one they think they're working on. He said the model in which utilities operate and are profitable must change. He suggested that some of this is in the regulatory arena and not the subject of your past workshop presentations. Mr. Binz said he would address the objectives a solar DG program should achieve, how to deal with the false precision of cost allocation and rate design, unbundling the utility-DG generator relationship, discussed the acceptability of net metering as "rough justice and offered some guiding principles.

Mr. Binz discussed the policy objectives of encouraging solar deployment, diversifying generation supply and reinforcing the grid. In discussing rate design, he reviewed the difficulty when the price signal does not correctly compensate a utility for its costs, noting that this results in a rate structure where there's a compromise somewhere. He also noted that that this is further complicated when consumers are both buyers and sellers or have some other competitive options. Finally, he reflected that complex rate structures are not accepted by consumers (and utility commissioners), at least today. One example of the challenge this presents is shown in slide 46. In CO, he said the top 20 percent of customers use 40 percent of electricity. He said, this suggests that it might make sense to adopt rate structures for customers who are qualitatively different—not just quantitatively different. He suggested one way of phasing in a TOU approach is to make it mandatory for the top 20 percent of your customers. He said these customers are really quite different than the "average" customer.

Mr. Binz suggested isolating the DG payment from the tariff rates under a "buy-all, sell-all" model. He said this approach sorts out the issues and addresses the desired policy objectives but it does not answer the issue of rate design. One challenge, he said, is that it's unclear how DG solar benefits compare to cost-of-service rates. He added that it's also important to recognize that given TOU pricing goals, the value of solar may be greater than the average price avoided by the customer under net metering. Mr. Binz suggested that the results of a new rate structure should be measured against the unbundled buy-all, sell-all model. He summarized that the net energy metering debate is only incidentally about distribution cost recovery; the primary issue is the evolving utility business model.

Mr. Binz next discussed a project, "Utilities 2020: Exploring Utility Business Models and the Regulatory Changes Needed to Transform Them." He said the thesis for this project is that utilities are under great pressure to change. He cited several factors including aging plants, tougher environmental regulations, flat to declining sales, new technologies, changing consumer requirements and weakened industry financial metrics. Mr. Binz suggested that regulation may not be up to the task of responding to these needed changes. He said the goal of this project was to explore new business models and advocate new regulatory models to enable new utility business models. He and Ron Lehr, also a former CO Commissioner, ran the project. They were advised by a board of experts. They conducted interviews with utility experts and leading state regulators, evaluated systems in the US and abroad, and engaged in dialogues with utility executives and commissioners.

Mr. Binz reported that utility CEOs said they want clearer, more consistent direction from state energy policies. CEOs noted they have little incentive for innovation and innovation at the firm level. Utility CEOs suggested that regulators need a better understanding of the utility business and its needs, that they want certainty on climate policy and healthier working relationships with commissioners and their staffs.
He added that commissioners said a primary concern is increasing utility rates. Regulators noted they are open to modifying the regulatory model and are looking for ideas. Some commissioners are dissatisfied with the adversarial process. Many commissioners said they face severe barriers to communications with stakeholders, and even fellow commissioners. Commissioners have inadequate resources.

Mr. Binz summarized that there are three potential regulatory models that should be considered in this reform:

- the UK "RIIO" model featuring a price cap built on RPI-X; agreed upon output measures and a decoupling mechanism;
- the "Iowa model" featuring 17 years of constant rates involving settlements every four or five years;
- the "Grand Bargain" focused on a regulator-led, comprehensive multi-year output-oriented deal.

Qs and As

Q: Concerning "cleaner and greener" as a policy objective, when you factor in the production of the solar components, is solar cleaner and greener than gas?

I think it came from NREL, but it might have been DOE. The solar value chain has now passed that break-even point. The processes that go into making a solar panel are now in the black, being spread out among the units produced, so the answer is yes. That's without a price on carbon. [According to a workshop participant, the report came from Stanford.]

Q: When you suggest TOU on slide 51, are you assuming dynamic TOU that shifts with the peak or a fixed TOU?

The realist in me says you start with a fixed rate, fixed period. That is a rarity in this country. This is considered to be complex. I think you start there and move to a more dynamic price is where we should be headed, but you can't get there in one step.

Q: As a former consumer advocate, did you have the opportunity to argue for or against deregulation?

No. It never came close in CO when I was in this position. By the way I don't know what you mean by deregulation, but I'll answer it anyway. Provisionally, I think wholesale deregulation can work as shown by PJM but I'm still open on retail deregulation.

Q: Under the UK RIIO model, earnings are decoupled from sales. Some of the outputs seem to be challenging, for instance "social responsibility."

Rates are not calculated on a rate base times rate of return. That could be the starting point. It's generally deemed to be the amount of acceptable rates, however you got there but for the eight years you don't look at investments. The utility is incentivized to choose the lease cost solution to maximize earnings. Social responsibility translates to how they handle low-income customers.

Q: Is safety included in reliability in the UK model?

Yes.

Q: In the past, we've had other major industries regulated by the Commission, such as transportation in AZ. This has been a big area of deregulation and has resulted in spectacular success.

CO used to regulate household movers, tow trucks, all passenger carriers. The question is has short-haul trucking been served by deregulation. There's some thinking that this is not the case. That pricing has gone out the window and that safety has been compromised. I'm humble about what regulation can achieve and lean toward market-based solutions. In practice, there are market failures, we just don't trace that. There's been mixed success in transportation. You tell me if the bankruptcy of every major airline a mark of the success or failure of deregulation.

Q: From the discussion earlier today, it seems there is a tension between looking at short-term avoided cost vs. long –term.

LRIC—Long-run incremental cost is what I would consider the most useful indicator. Yes, longer-term. Hourly avoided costs is pretty useful for dispatch order in PJM. But that's not lead to long-term capacity planning so they've invented a capacity market to help with the longer-term stuff.

Q: You made a couple of very good points: society's goals are changing and the ratemakers consistently say that the No. 1 concern is not increasing costs. Please indulge me in this analogy

to illustrate my point: Ten Arizonans go to dinner and agree to go Dutch. They all have different appetites but will eat the same meal. Eight to 9 of these people want their meal made from organic, locally grown ingredients, even if they pay a premium. One or two of these diners want their meal made from the typical wholesale ingredients which they assume will cost less. So the manager and the chef get together discuss the shelf life, availability, ease of cooking these ingredients. They do the math and find out that one does indeed cost more. So they decide for their customers that they will serve the cheapest option. This activity under the RIM test is a loser's scenario and is exactly what we're doing right here. At the risk of being foolish, I ask, "Where are the voice of AZ ratepayers being accounted?"

Who are you asking? After all that analysis, they still split the check and the people who don't drink expensive wine took it on the chin. You deserve a serious answer. I don't take regulation, including the RUCO involvement, as Ionian democracy exercises. We're supposed to be leaders. It's not a matter of finding out what everyone wants and doing that and ensuring everyone is heard. This isn't town meetings in the street. As CPUC chair, I found out that people were willing to pay more if they thought they were getting more. I think you can do things that cause rates to go up. In the UK, regulators are focused on evaluating the value they're getting for what they're paying. Here, we're focused on the opposite question: Did we pay the right amount? We might be better served by turning that question around, understanding that we're going to be paying something and asking what we are getting out of it.

Q: In the restaurant example, deregulation is the perfect solution. If we want the cheap meal, we can get it. If we want the organic, high-cost meal, we can also get that. This is where we ought to go.

I think deregulation is not the answer in and of itself. It might be the solution to certain problems. I never trust a simple answer to a complicated issue.

Stakeholder perspectives

- **You mentioned how environmental aspects aren't taken into consideration in a deregulated model. I think we need to consider what most Arizonans want and that's clean energy. Why shouldn't that be taken into consideration? This means retail completion for electricity.**

APS Conceptual Solutions (Slides 66-69)

Chuck Miessner, APS, made a presentation on several issues APS is considering in examining potential solutions. He noted that a question was asked in the morning as to why APS was talking about solutions when the workshop is not yet finished. He stated the answer is that APS doesn't have a solution yet. He said APS staff are here listening, digesting the information, looking around the country and at other things that are happening. He said APS thought it would be helpful to present what it's hearing and what it's investigating as potential solutions. He first discussed rate equity issues. Potential solutions are in two camps, he said:

- Rate Design concept. Value and benefits are tied to what is avoided on the retail rate schedule. This includes rate designs or modifications to existing rate structures that better align some of the services provided.
- Total DE Export concept. Also called the buy-all, sell-all model. This is the value of solar model.

Mr. Miessner said that APS is also considering what to do with the net metering billing construct. He said APS staff are asking, Do we need any revisions? How does that fit into these models? He noted that this doesn't fit under the Total DE Export and reflected that APS may also need to address incentives.

Qs and As

Q: I took Ron's point to be that that you can calculate the value of solar separately. But under these approaches you are looking at the value compared to the cost. Under the Rate Design

concept, if the end result is that the value is more than the cost, are you considering how you would provide that value to the customer?

The second model is a separately billed, separately accounted approach. Under the first concept, you might benchmark the benefits that a solar customer gets to the second one. That's part of our investigation. We're considering aligning costs types to rate types. The second construct is that while I'm not paying all of my costs, I'm decreasing your marginal costs so much out into the future that that present value cost reduction makes up or more than makes up for my part of deficit today. So I'm even or almost even.

Q: I think the "buy-all, sell-all" model because I think it correctly captures the exchange of value. Whatever you do it needs to be measured by that exchange. If you do it right, whatever that means, that's the correct answer. Paying a premium needs to be a possible answer if this is how the value comes out.

That's really part of the grappling and thinking on this issue. How do you fold in the long-range marginal value, marginal cost reductions into current rates? Currently we don't charge people that use more based on long-range margins. We don't say, by the way you caused a new addition so that's 19cents a kWh because of all these marginal costs you put on our system. We're grappling with if someone reduces their load, should we be rewarding them for that 19 cents per kWh. We're still looking at this and not sure where we're going to end up.

Q: What about the Total DE Export? Is that similar to what currently occurs with the end of year true up?

It's more similar to the Austin Energy construct where there wouldn't be any netting or banking. On a monthly basis we would buy all the energy at whatever the right value was. This would be separate from your retail rate calculation. Right now, we true up and cash out at the end of the year.

Q: Have you considered having both the "buy-all" and net metering as MN is now considering? Customers can choose one or the other.

That could be part of it. We're already stressing our customer service representatives with the current choices but we haven't yet ruled anything out.

Q: What about grandfathering? We have long-term contracts out there. Is there a possibility of that?

I think that has to be part of the conversation. We haven't put a proposal out yet but we have talked about how to make this fair to everyone and we agree this is important to address.

Q: It's more complicated than grandfathering. We have 20-year leases. If someone moves, are they grandfathered to the next resident?

I don't have an answer for you. We have talked about that issue as well.

Q: Under the buy-all, sell-all model, it's worth keeping in mind that if customers have to sell all their output to the utility and buy what they use, they can no longer reduce their use by consuming what's on their roof. Under this approach, customers can never become more independent or reduce their electricity bills.

I agree that's a consideration. There are plusses and minuses to each of these. Under the first construct, that's what people are used to. That's one of the advantages. It keeps the transaction similar to what they're used to. Under the second category, your bill would go down. You'd still see the charge for electricity use, but you'd also see a credit for the sales. Your bill would go down, but it would be a different transaction.

Q: I'd encourage looking at different business models for different sectors. Commercial could be a great buy-all, sell-all and residential could be a variation of what we have now. Suggest keeping aware of where different customer classes are savvy. The other idea that was really intriguing was the statement that we don't charge new customers on the margin (e.g. we don't charge them 19 cents...). It's an interesting thought experiment, when you have a new power plant and the levelized cost is 9 cents and this is spread over and averaged into avoided cost

rates. In a way you're spreading those new incremental costs to everyone. Can you explain this?

It's not spread into our avoided cost rates. It's spread into our cost of service rates. A 15-year old powerplant that's half depreciated is what we recover in rates. We have a mix of that one and the brand new plant. We don't say everyone who lives in Phoenix now gets this deal, but the next person has to pay a higher rate based on the incremental cost of the new substation, new transformer, etc. We average everything together. If your 30-year old transformer has to be replaced, we don't charge you for the new one. We are used to average cost rate-making and that's how we do it. We don't charge people on the margin so we're grappling with rewarding people on the margin.

Q: I think it's amazing that on the residential side we have inclining block rates and on the commercial side, we have cut your rate in half of increases in sales. Why do we still have that?

Both the inclining block and the declining block are 1950s vintage concepts .We really don't have declining blocks in the business sector but it's a little more complicated. For small and medium customers, we have embedded demand charges in the first block based on your load factor. But there really isn't a true declining block kWh charge. We're just capturing some demand charges in the first block. I thought I heard Ron say that TOU structures may be a better match for category 1 because they more appropriately reward solar for on-peak power costs. I think one of the advantages APS has is that we're one of the few utilities that really does have a high penetration of TOU customers. Most utilities have a 1 percent or ½ percent penetration. We have 52 percent penetration of residential customers on TOU. On our solar DE customers it's about 60-percent penetration on TOU. Our customers are already used to TOU pricing.

Q: One observation on the buy-all, sell-all construct is the greater complexity for the customers in having two rates—one for power coming in and a second for power going out. There's also the complexity of over time trying to figure out how those two prices will change over time. If your TOU period shifts over time, you can modify your tariff rates. You have to decide if similar changes will flow to the sales rate customers are getting for their output. If you have a net metering or some kind of rate design concept, if you more closely align your retail rates with your costs that would also flow through to the value of the power.

Thank you. I think that's a very fair observation. If you change your basic rate design to better align your recovery, people know what that is. For the second category, once you try to project avoided costs out over time, you've seen the difficulties in this room in determining what's legitimate. Do we have this debate every two years? Is that a good business practice?

Q: Can you expand on the incentives that might be considered?

We're not saying incentive will be needed. What we've heard is that if you take some of the value out of the rate design, is that going to be adequate to support solar business development. If not, do you consider some other kind of up-front incentive or other financial incentive that helps make that cost-benefit or payback work for them. We don't have a proposal. It's just an observation we've heard. It's been suggested that we might have to consider teeing up incentives.

Q: Is the thinking here to take what may be perceived as an incentives out of rates and put it into the tariffs?

Yes. That's it exactly.

Q: I'm curious if you could share APS' or your own personal view of the ability or interest level in doing your version of the Austin plan with DE rates?

It's certainly on the table. We've teed it up here. It's one we're investigating so we don't have a handicap which way we're leaning, because we're not yet leaning.

Q: One of the questions I have is would APS consider eliminating the demand charge for solar customers? This is one of the classic problems from schools and churches where they end up with a higher bill than before because of the demand charges. One of the questions in rate design tweaks, would you consider eliminating demand charges as an incentive for solar?

Our business and commercial customers all have demand charges today. Hopefully they understand them. This is nothing new. For our very small customers, 20 kW peak demand or less, such as billboards, repeater stations, the Hallmark store at the mall, they don't have demand charges. If we did anything there it would be new for them.

Q: I'm suggesting eliminating demand charges for business customers that now have them.

I think we'd be going in the wrong direction. We're trying to recover costs. The other thing that we're trying to determine is which rates do we try to change. Some look pretty good where they're at.

Q: I've seen a number of different proposals. We're going into this discussion with the idea that there's a problem that needs to be fixed. We've heard several perspectives and I think that Tom has done a good job of explaining options for rate equity. One of the problems with the Austin approach is that the rate fluctuates from year to year. This makes it difficult to get financing because you can't project what that revenue stream will be. From a developer's perspective, this is very challenging?

How much stability do you need? Is it five years? 10 years? 20 years? Rates change over time.

Q: It's pretty predictable that rates aren't going to go down. A feed-in tariff like Germany has is perfect. A relook every year like Austin in much more difficult.

Thank you. Thanks good input.

Q: Previously you talked about averaging rates across customers, where new customers don't pay the incremental cost of new infrastructure. There's no perfect rate. People aren't charged what they should be. This makes perfect sense for line extensions where the costs are socialized over the entire rate base. I don't think that net metering is an issue here in terms of cost shifts. So why is net metering being called out specifically unlike many of these other cost shifts?

Some of these other issues, subsidy issues are known. For instance, business customers subsidize residential customers. Without this, business rates would be lower and residential rates higher. That's been vetted in many previous rate cases and decided by the ACC. The line extension policy has been both ways. A previous commissioner believed that new developments needed to pay for new facilities. There was tremendous customer back lash and that's gone the other way. All we're suggesting is that we need to bring this out in the open. Solar's growing exponentially. We need to have this conversation now and not five years from now when we have a lot more systems on our grid.

Q: While it's true that churches and schools did have that demand charge prior. I consider it a fault of the solar industry that we didn't have the right people educating the customers. But one thing APS can do to help bridge that poisoned relationship, is any time a customer with a demand charge applies for a solar hook-up is to send them a one-page document they have to sign acknowledging that there are certain costs that cannot be deferred and solar may not reduce their highest energy consumption. That's a step in the right direction in building a strong relationship between the customer and the utility. That would also help with their solar deployment.

Thank you. Good comment.

Q: Sometimes, at least for E032 L, let them know that a rate change may happen.

Q: If you're bringing on a new generation asset and it's more expensive than your average price for energy. That PTA is more expensive. That's spread around. I keep saying this because finding a solution is going to be very difficult if we can't get together to figure out if we should look at future benefits or just avoided cost of today plus a little extra. That is just such a fundamental issue to solve that we should be spending some time on it. I want to keep exploring this. Rewarding a solar customer that's generating on the margin is equivalent to charging a new customer on the margin. I don't know if that's a proper analogy but I wanted to explore it.

That's kind of front and center. I don't know if they're equivalent. We're looking at category 1 in the Rate Design concept. There, we're not talking about avoided costs, even short term, we're talking about embedded costs. This is the existing power plants—new and old, along with the transmission *and distribution equipment whether it's three or 30 years old, all averaged together. We charge for that average cost by rate category. There's a lot of math to try to get it fair. My comment is that we at APS have heard a couple of approaches and numbers and we're wondering is it valid to look at future costs that might be reduced and reflect those in someone's cost for service that they get today. This may be partially valid, it may be fully valid. That's part of our thinking in trying to bring all of this information together to determine what we should to do cost everything out fairly for everybody.*

Q: I want to build on something that was said earlier about the stability of cash flows and what financiers need to put money into the system. We work on a lot of commercial systems in AZ. We've found out that financiers don't value anything that's not contracted. Wild fluctuations in an income stream—such as APS paying a variable rate for generation—will dramatically increase the cost of financing. Lower cost financing has allowed us to grow. Please consider this.

Thanks, these are great comments.

Q: I think we need to have that honest discussion about future costs. We're stuck in this position of having a historic test year and it doesn't really allow us to think outside the box. This is an important discussion to have. As that conversation unfolds, think about the key assumptions. There are a lot of buried assumptions in the modeling. If you tweak some of those, it totally changes the equation and how you think about future avoided costs. We need to think about that.

Thank you.

Q: What APS is concerned about is the revenue loss and this is based on embedded costs, average rates. It's based on all the old stuff—depreciated plant, so a pretty low average costs. On the other hand, what the net metered system is saving—it's not reducing any of those costs because they're embedded—its' reducing future costs. If the net metered system wasn't there, those future costs would be socialized across all ratepayers. The argument is that we're avoiding at least a portion of those costs so that portion should be credited to the net metering customers. It's those higher future costs on which the credit should be calculated on. That's why we end up with benefits that exceed costs. The embedded costs are lower and the future costs are higher.

I understand the position. Those future costs would be socialized to everyone in the future in a future rate case. Is it appropriate to give a solar customer that value today before we even realize that value? That's part of the question. With the timing of when that folds in. We also have an issue of marginal and embedded here, too. I understand your position.

Q: One other thing that's possibly on this list. Customers disconnect from APS and are on their own. Right now that seems like a fantasy because it would cost too much. But DOE is spending a lot of money on battery research. That research is going on around the world. If the other options aren't offering much, 4 cents per kWh, the logical thing to do will be to put in a home system and disconnect. That will be a suboptimal solution I suspect. It makes better sense for APS to offer net metering to those customers rather than for them to go away all together. I'm wondering if APS has compared which scenario it would rather have—those 14,000 customers connected or not?

[laughter] We'll think about that. We like having customers. They have that option today. On the other hand, if we're not getting recovery for our services, maybe we're indifferent.

Q: A less dramatic question: Are you looking at rates that would recognize a residential customer accepting lower reliability?

Not in this proceeding. This one is complicated enough. We need to cut down on the moving parts.

Q: This question is for Nick [Theisen, SOLON Corp.]. Is there a business model that would work with financiers if there's a tight tolerance around whatever rate it was? If there was a buy-all, sell-all that was fluctuating a bit, but there was a tight tolerance, say it only fluctuated one cent per kWh up or down, do you think that would be OK? What's the tolerance you need for planning?

My understanding of how financiers value things is that there are plenty of models that take this into account. We have worked on projects that consider the CPI. If you can see some kind of band around what cash flows would be, they can get comfortable with this.

Q: I'm concerned how buy-all works. How do you force the customer to sell to you and not divert it to loads he has?

You can do it by electrically connecting to the grid or through the billing system. We know how much energy is coming out of the generator.

Q: What if I intercept the output of an inverter and switch it only when the air conditioner is running?

[laughter] What is your address?

Q: I'm on SRP.

Then you're OK.

Q: That's the practical side. This opens up things that are going to be very difficult to police.

Thank you.

Q: What are other utilities doing?

On the DE Export concept, most people are talking about the Austin approach. On the rate design approach, we're talking to San Diego. This isn't an implemented rate but a brand new rate design, either just for solar or for everyone. You could also tweak existing rate design. We've seen that with a proposal by Idaho Power where they've taken their distribution charges that were kWh-based and converted it to a demand and a basic service charge. We've also seen Dominion Power in VA with a very limited standby charge for residential customers above a certain size.

Q: Generally these are all concepts that haven't been approved by Commissioners?

The Dominion rate has been approved. Idaho is a proposal now.

Q: How do we know that we avoid a plant when we're considering future costs? It seems tough to capture those savings. What happens if you give a premium for future savings that are never realized? How do you compensate customers without overpaying?

That's a very good observation.

Q: With the buy-all, sell-all idea, have you looked at whether you could mandate buy-all, sell-all. My understanding is that the net meterer is a QF [qualifying facility] is under PURPA and they have a right to sell excess if they want to. Is this a barrier to a buy-all as the only option?

I don't have an answer. We'd have to get a determination on this. That's part of the homework. Do you have an opinion on this?

Q: What I understand is that under PURPA you have a right to sell the excess. It's a choice of the QF not the utility. We had a proceeding to implement PURPA in AZ. We have a ruling on this.

For the QF, we have to take all of their output at avoided cost. Net metering customers may be QFs if over the applicable billing period [a year] they have net sales onto the system. That's what would trigger FERC jurisdiction for interconnection or any of those other things. Any generating system under a MW is automatically a QF. It gets really complex, but I'm happy to answer any questions offline or now.

Q: On the buy-all, sell-all, you really need to ensure you are considering all the benefits. On the energy efficiency that Tom spoke about earlier, he had the energy efficiency as well as the export piece. Under the buy-all, sell-all approach, the energy efficiency piece gets lost and I'm not sure if the value gets portrayed. How can we ensure that this doesn't get lost?

The energy efficiency piece of the solar generator?

Correct.

Under the buy-all, sell-all construct, you're not separating out the self-service and the export piece. There's no split. The entire output is going to the grid. You will still get a bill savings.

Q: On the margin, the incentive on your solar generation is the same under both options.

Thanks.

Q: To what extent could APS alter net metering and not violate PURPA?
PURPA did not require net metering. EPAct 2005 set up standards for net metering. State commissions must consider them and either affirm them or not. The ACC did adopt them.
Q: We may want to think about the taxation treatment of PV systems, specifically related to the issue of self-consumption vs. for sale. The buy-all, sell-all model may have an unintended tax consequence.
Thank you.
Q: There are a couple of FERC cases on the ability of a QF to self-supply without discriminatory treatment. I'll send the references to APS.
Thank you. That's part of our due diligence, making sure we understand all the issues and regulatory requirements.

Stakeholder perspectives

- In the rates in the commercial world, customers don't know what their demand is and we're still waiting to get those meters out to them. I wonder why we really need that pricing signal. In CA, they've been emphasizing TOU which gives customers a signal that it's expensive to use electricity at certain times when the system is challenged. When I think about capacity and if you need a capacity charge, I think about buildings. They are sized based on some standard, not on what the customers actually use. So a lot of the distribution is based on that, not what the customer is actually taking. So you're talking about the powerplant side and some of the transmission lines. It seems that TOU isn't getting enough emphasis. They are unfavorable compared to other plans. I think there should be more emphasis on TOU. I've seen plenty of customers that have peaks not coincident with the system and some of them don't even know that. You mentioned that there's high penetration on the residential side. I think that's because people can understand and can deal with, whereas most people don't even know the difference between a kW and a kWh much less how to respond to a peak demand signal.
- The EE benefit in the buy-all, sell-all depends on your retail rate. If you're a commercial customer with an avoided cost of 7 cents and the buy-all, sell-all payment is 12 cents, you don't care about avoided. There's also capacity values.

Next Steps and Session Wrap Up
Bob Davis wrapped up the session by noting the remaining schedule, targeting May 28 for the Closing Forum. He said this session will provide participants a chance to get in a last word and for the facilitator to summarize what's been heard during this Technical Conference. He said all documents need to be submitted by May 21 as well as input on the cost-benefit matrix. He said to expect the facilitator's report to be available in mid June with APS' proposed solution published in July.

He reminded participants to send cost-benefits comments to either Bob or LaVerne and other comments and questions to LaVerne.

Qs and As
Q: On the cost-benefit matrix, can we agree to short entries?
Yes, if you have longer documents, footnote them and we'll provide them with the other documents submitted.

Forum and Workshop Goals

- Meet Arizona Corporation Commission expectations
- Create stakeholder collaboration
- Focus activities on education and engagement
- Develop common understanding of issues and options as we work through solutions
- Create an understanding of critical challenges

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Review of Technical Conferences

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Opening Forum
February 21, 2013

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Opening Forum

- Welcome by Jeff Guldner, APS Senior Vice President
  - APS goals and critical challenges for adding distributed energy
  - Purpose and goals of technical conferences
  - Costs and benefits to renewable and non-renewable customers
- Mark Gabriel
  - Goals and process
  - Develop a common understanding of the issues, options and challenges
  - Alignment

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Opening Forum (cont.)

- Stakeholder Perspective on Workshop Goals and Subject Matter
  - Identify costs and benefits DE (comprehensive)
  - Best practices for cost-benefit studies
  - Need transparent, data-driven process
  - Use industry studies
  - Consideration of energy storage
  - Fossil and nuclear subsidies
  - Stakeholder agreement with and involvement in studies
  - Stakeholder access to data sources used in cost-benefit studies
  - Retail rate fairness and equity, rate stability, long-term rate impacts, ratepayer value

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Opening Forum (cont.)

- Stakeholder Perspective on Workshop Goals and Subject Matter(cont.)
  - Inadequacy of current rate design
  - Cost-effectiveness perspectives (rate impact measure, RIM)
  - Drive technology innovation and new business models
- Issues that may not be addressed by technical conferences
  - Need for R&D, pilot studies, new approaches
  - Create a sustainable industry future for DE in AZ
  - Qualified solar installer program
  - Consumer education when purchasing DE
  - Retail rate transparency
  - Commission involvement in the process
  - Value of storage in the cost-benefit study

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Opening Forum (cont.)

Net Metering Overview, Eran Mahrer, SEPA

- Dramatic issues and unprecedented opportunities
- Changing customer demands - regulatory models require adaptation
- Net-metering is widely available
  - Utilities in over 43 states offer net-metering
  - Easily explained to customers
- Rate impact may not match utility costs and benefits
  - Power export and energy efficiency impacts
  - Current net-metering rate models do not recover fixed costs
  - Customer bill reductions/refunds exceed utility avoided costs
  - Provides poor market signals to DE customers and industry

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Opening Forum (cont.)

Net Metering Overview, SEPA (cont.)

- Net-metering design, two camps:
  - Net-metering works, don't change it
  - Reevaluate net-metering to provide equitable cost distribution and full cost recovery
- Possible net-metering redesigns:
  - Demand based rates
    - Simple, already in use with large customer rate classes
  - Net cost of service to serve DE customer
    - Analytically complex
  - Value of solar (consumption and production are separate)
    - Consumption at standard rates
    - Production at avoided costs

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Opening Forum (cont.)

Net Metering Overview, SEPA (cont.)

- Many value attributes of DE are long-term
- Even with equal long-term value, near-term impacts to ratepayers are not equal
- Recommendations discussed:
  - Quantify value of DE
  - Establish transaction model that supports DE and customers
  - Maintain simplicity
  - Minimize the need for subsidies
  - Maintain recovery of utility costs

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Opening Forum (cont.)

APS Perspective, Greg Bernosky, Renewable Energy Mgr.

- Customers changing how they consume (and produce) energy
  - Solar DE is available to a greater number of customers
- APS response
  - Maintain safe and reliable power supply
  - Recover infrastructure invest and operating costs
  - Modernize rate design to manage cost impacts for both DE participants and non-participants
- Billing offsets should match utility net avoided costs of DE
  - Identify unbundled costs of service
  - Identify role of incentives or subsidies, if any
  - Make solar DE sustainable through new rate design

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Opening Forum (cont.)

- Introduction to future technical conference subjects
  - Retail rate making
    - Revenue requirements determination
    - Unbundled cost of service determination
    - Rate design development
  - Integrated resource planning
    - Avoided operating costs
    - Delayed or avoided facility investments
    - Possible cost increases
    - Utility load shape impacts
  - SAIC refresh of RW Beck 2009 DE Study
    - Refresh of 2009 RW Beck study
    - Discussion of major changes to key assumptions
    - Review of data sources

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Opening Forum (cont.)

- Summary of Stakeholder Q&A and general comments:
  - Net metering is not broken and does not need to be fixed
  - Output of the process should be a comprehensive cost-benefit study
  - Various natural gas price and environmental scenarios should be considered as part of the SAIC study
  - Concerns that single-axis tracking PV, various PV orientations, and solar water heating will not be part of the SAIC study
  - Interest in expanding the schedule for the technical conferences to permit stakeholders the chance to direct the study approach and to participate in SAIC analysis and modeling
  - Stakeholders were asked to develop a list of costs and benefits categories for inclusion in the SAIC study

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Workshop I
Understanding Rates and DE Benefits
March 7, 2013

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Workshop I

- Workshop Opening, Review of Stakeholder Goals, and Alignments
- Preliminary overview of SAIC refresh study process
  - Review of data sources and request for comments and suggestions
  - Review of key assumptions
- Summary of stakeholder Q&A:
  - APS data on monitored solar PV is being utilized in the study
  - Stakeholders will have access to the APS solar data
  - Stakeholders will be provided the data being provided to SAIC, to the extent possible
  - The SAIC results will be reviewed in a manner to provide transparency
  - SAIC will utilize PROMOD simulations of the APS system
  - SAIC will validate PROMOD input assumptions
  - SAIC will validate that PROMOD results are consistent with expectations and experience
  - The PROMOD model will not be benchmarked to market price data
  - SAIC will modify model inputs to perform sensitivity analyses

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Workshop I (cont.)

- Summary of stakeholder Q&A (cont.):
  - The PROMOD modeling will use hourly solar load shapes
  - The value of DE on avoided capacity is included in the study
  - The SAIC study will be expanded to include results for 2020 (in addition to 2015 and 2025)
- Summary of stakeholder general comments:
  - Study needs to consider scenarios that incorporates technology and fuel market variations
  - Solar water heating should be included in the study
  - Stakeholders have not received the same access to data assumptions/inputs as SAIC [APS noted that SAIC had not yet received the full data set at the time of the workshop. Additionally, the workshops schedule was extended to provide the stakeholders more time.]
  - The study should reflect the utility capacity avoided by existing DE installations
  - Modeled solar implementation should include scenarios of two- and four-times current implementation levels

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Workshop I (cont.)

- Additional data considerations (Tom Beach for SEIA)
  - Market price mitigation
  - Benefits from southwest or west facing orientations of fixed arrays
  - Grid security benefits
  - Fuel hedge value
  - Environmental compliance savings
  - Reliability benefits
  - Environmental savings (like water)
  - Avoided RPS wholesale purchases
- APS is reviewing these additional data considerations and will address at a future date

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Workshop I (cont.)

Utility Rate Making, Tony Georgis, New Gen Strategies and Solutions

- Primary steps in rate-making:
  - Determine revenue requirements
    - All reasonable expenses, cost of capital, taxes, and fair rate of return
    - Test year analysis
    - Known and measurable adjustments
  - Allocate costs:
    - Functionalize costs (production, transmission, distribution, etc.)
    - Classify costs (demand, energy, customer costs, etc.)
    - Allocate costs among rate classes (load shapes, coincident/non-coincident demand, etc.)
  - Design rates
    - Cost curves
    - Objectives
    - Rate components

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Workshop I (cont.)

Utility Rate Making, Tony Georgis (cont.)

- Subsidization
  - Intra-class subsidization
  - Inter-class subsidization
- APS current costs and rate structures
  - Alignment of variable and fixed costs and revenue
  - Unbundled rate components
  - Adjustments
- Summary of stakeholder Q&A and general comments:
  - Lack of alignment of fixed and variable costs and revenue is not caused by solar DE, but solar DE makes the problem worse
  - For commercial customers, fixed and variable alignment is not as big a problem, but variations in load factor cause subsidization
  - When using a historical test year, rates are designed to cover historical, not forecast, costs (Arizona does not allow a forward-looking test year)
  - Rates are set based on embedded costs, not marginal costs
  - When computing rates, non-coincident demand is used to measure the facilities required to meet the demand of the customer when DE is not operating.

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Workshop I (cont.)

APS Rates Overview and Impact of Solar DE, Charles Miessner, APS

- APS major rate classes
  - Types, customer, energy and revenue allocations by class
- Billing elements and charge types
  - Fixed charges, variable charges, and mixed (tiered rates)
  - Bundled and unbundled components
  - Adjustments
- APS specific rate designs and DE bill savings
  - Example DE billing component savings
  - Example utility cost savings
- Conceptual discussion of cost-shifting *billing gap* issue
  - Cost equity test (utility cost savings = bill reductions, then no adverse impacts)
  - Billing gap (utility cost savings < bill reductions, then costs shifted to non-participants)
  - LFCR used to collect fixed costs from all customers, does not correct cross-subsidization

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Workshop I (cont.)

APS Rates Overview, Charles Miessner (cont.)

- Review of Navigant Study
  - Characterize cost shifting and rate impacts of DE
  - Evaluate potential cost equity issues
  - Assess compatibility of APS rates for rapidly growing DE
  - Study was not a cost-benefit analysis, IRP, evaluation of utility financing/earnings, or quantification of impacts on all customers
- Major Findings
  - Under current rate designs, DE shifts costs to nonparticipating customers
  - Current APS rate designs are not sustainable with a growing level of DE
  - Net-metering exacerbates cost shifting
  - Cost shifting is highest for residential and small business customers because the rates rely on kWh charges for fixed cost recovery

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Workshop I (cont.)

APS Rates Overview, Charles Miessner (cont.)

- Summary of stakeholder Q&A and general comments:
  - Navigant study missed important benefits. Benefits are to be addressed by the SAIC study.
  - Navigant study utilized actual metered solar DE, applied to representative customers, to investigate sensitivity of cost equity to key assumptions
  - The study focused on rates classes with the greatest potential for cost shifting, other rate classes were not studied
  - Study focused on current impacts, not long-term benefits. Both costs and rates grow over time, so problem will persist.
  - Other known types of rate subsidies have already been vetted in rate cases; subsidies caused by DE has not yet been vetted
  - Total subsides caused by DE are small today but are expected to grow significantly over time

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Workshop I (cont.)

APS Rates Overview, Charles Miessner (cont.)

- Summary of stakeholder Q&A and general comments:
  - Similar cost shifting issues exist for energy efficiency and conservation, but the level of cost shifting per participant is lower
  - Cost savings are based on installed assets, not future avoided costs
  - APS may receive RES credit for DE, which provides a benefit to APS
  - If benefits exceed costs, then subsidization is reversed
  - The billing gap for APS is approximately 15 cents, higher than referenced in the 2009 RW Beck Study, largely due to falling natural gas costs
  - The Navigant study did not consider costs for DE integration
  - Solar DE acts as a hedge against future natural gas prices, but doesn't eliminate all risks and may shift risk exposure from market volatility to fixed obligation
  - Large numbers of DE installations improves diversity and reliability

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Workshop II
Resource Planning and DE Costs
March 20, 2013

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Workshop II

- Workshop Opening and Review of Workshop I
- Alignments (from Workshop I and II)
  - Transparency is critical
  - Subsidies for all fuel sources should be considered
  - Additional studies, in addition to the Beck study, should be considered
  - Consumer education is important
  - There is a need for continued consideration of new applications
  - Definition of net-metering (see meeting notes)
  - DE rate impacts can occur through behind the meter rate offsets (self supply) as well as net metering bill credits
  - APS rates are based on historical test years
  - DE impacts both costs to serve and revenues collected
  - DE customers have a unique load profile, benefits, and costs

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Workshop II (cont.)

- Not aligned
  - There should be a level playing field among distributed energy technologies
  - Current rate design may not be compatible with distributed energy
  - Rates need to consider impacts of DE participants and non-participants, while supporting utility cost recovery
  - Solar energy provides economic development opportunities for AZ
  - APS service is highly driven by fixed costs
  - For residential and small commercial rate categories, there is a mismatch between cost types and charge types (causation vs. recovery)

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Workshop II (cont.)

Evaluating the Benefits and Costs of Net Energy Metering in California, Tom Beach, SEIA/Crossborder Energy

- Net energy metering (NEM) is simple and easy for customers to understand
- Impacts of NEM on non-participating customers is complex
- Under PURPA, customers have rights to interconnect, offset their own load, and receive avoided cost payments for exports to the grid
- Does NEM rate credit accurately capture the value of exported power
- NEM evaluations should use the same approach used to evaluate demand-side resources
- Cost-effectiveness of NEM (net export) and DE (all DE production) are not the same
- NEM cost-effectiveness should be performed using the RIM test (California uses the TRC test)
- NEM from DG is a long-term resource (long-term costs and benefits)
  - Costs - lost revenue, integration costs, incremental administration,
  - Benefits - avoided generation costs (energy and investment), avoided environmental, RPS value, avoided T&D investment, avoided losses

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Workshop II (cont.)

Evaluating the Benefits and Costs of Net Energy Metering, Tom Beach/SEIA (cont.)

- Common misconception is that NEM credits result in customers that do not pay for certain utility services
  - NEM exports are more valuable than the average cost of generation credited through rates
  - Power exported by NEM customers should be treated similar to generators, who do not pay for power delivery (recipient of power pays delivery costs)
- PG&E has noted a 25 cent subsidy paid by non-participating residential customers
- 2009 E3 analysis forecast NEM subsidies at $137/yr (0.4% of IOU revenues)
- Recent changes in forecast utility costs and rates, and values of offsetting RPS have resulted in lower subsidy levels

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Workshop II (cont.)

Evaluating the Benefits and Costs of Net Energy Metering, Tom Beach/SEIA (cont.)

- Major categories of cost and benefits from CPUC-E3 study
  - Energy - all-in CCGT cost less CT capacity cost
  - Capacity - CT fixed cost (top 250 hours)
  - Avoided T&D losses
  - GHG allowances
  - Reduced ancillary services costs
  - T&D marginal capacity cost
  - Avoided RPS cost
  - 20-year levelized value of NEM solar exports exceeds cost of baseload energy

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Workshop II (cont.)

Evaluating the Benefits and Costs of Net Energy Metering, Tom Beach/SEIA (cont.)

- Crossborder CA NEM Study
  - Same methodology as CPUC-E3 study
  - Evaluate value of NEM exports for bill credit and avoided utility costs
  - Compute for multiple bins of different customer size and PV system size
  - Conclusions:
    - Solar NEM has a positive net benefit (utility costs are reduced more than are paid through NEM rates credits)
    - Two of three CA IOUs show no cross-subsidization between residential participating and non-participating customers
    - All three IOUs show no cross-subsidization for C&I customers
    - Greater adoption of TOU rates reduces cross-subsidization

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Workshop II (cont.)

Evaluating the Benefits and Costs of Net Energy Metering, Tom Beach/SEIA (cont.)

- Summary of stakeholder Q&A and general comments:
  - Integration costs are not included in the E3 model (CA has not adopted assumptions for integration costs)
  - Allowance costs are $10-13 for 2013 in E3 model
  - Avoided T&D costs are based on regression methodology
  - Once RPS is met, DE will still have value through exports and likelihood of increasing RPS standards
  - Intermittency of individual DE is managed through aggregated installations; benefits may be lower on individual circuits
  - In the E3 model, solar DE capacity does not diminish with increasing installations
  - Other studies indicate a correlation between cloud cover and decreased demand, but effect takes hours to occur in AZ
  - The E3 model captures hedge cost value by using forward market prices

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Workshop II (cont.)

Resource Planning & Distributed Energy, Bob Davis, nFront Consulting

- Electric utilities are responsible for providing reliable power at low cost
- Regulations may require utility-sponsored demand-side resources (energy efficiency, DE, etc.)
  - APS is currently planning to meet EE targets and is forecast to meet or exceed RE and DE targets
- Utilities will consider demand-side implementations if they pass certain benefit/cost tests (utility cost test, RIM test, TRC test)
- Solar DE impacts utility operations and planning
  - Changes generation dispatch (generally reduces operating cost, but can cause increase in operating costs during some periods)
  - Reduces need for future generation capacity additions
  - May incur costs to integrate solar DE

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Workshop II (cont.)

Resource Planning & Distributed Energy, Bob Davis (cont.)

- Evaluation process (general description)
  - Develop solar DE load shapes and forecast implementations
  - Adjust load shapes for energy and demand losses
  - Compute dependable capacity for solar DE
    - Adjust for demand losses
    - Effective load carrying capability (ELCC)
    - Coincident with electric system peak
    - Diminishing capacity value with increasing penetration
  - Avoided capacity costs
    - Assess utility capacity additions with/without solar DE
    - Identify avoided or deferred generating units or capacity purchases (solar DE avoids similarly performing generating resources)
    - Capital costs of avoided or deferred generating unit addition and transmission interconnection
    - Other fixed O&M costs of avoided or deferred unit

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Workshop II (cont.)

Resource Planning & Distributed Energy, Bob Davis (cont.)

- Evaluation process (cont.)
  - Compute avoided marginal energy costs
    - Generation dispatch simulation
    - Fuel costs, variable O&M, emission allowances, start-up costs
    - Simulation with and without solar DE
    - Compute avoided marginal costs
  - As larger quantities of solar DE are installed
    - More difficult to accommodate DE resources in the generation dispatch
    - Inefficient dispatch operations can result
    - If solar DE installations are not timed to match utility capacity additions, value of DE may be reduced
- Conclusions
  - Solar DE can avoid both energy and capacity related utility costs
  - Dependable capacity of solar DE is important
  - Solar DE benefits may be less than anticipated as a result of dispatch inefficiencies and timing of solar DE installations

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Workshop II (cont.)

Resource Planning & Distributed Energy, Bob Davis (cont.)

- Summary of stakeholder Q&A and general comments:
  - APS is looking at small 100 MW increments of generation additions when evaluated avoided capacity costs
  - There is no industry-preferred model for analyzing capacity expansion
  - APS is using PROMOD to model energy costs, not market price modeling; DE may cause dispatch inefficiencies for APS that would not be reflected by a market price forecast
  - Discussion of whether DE production can be sold to a neighboring subdivision, thus eliminating the need for the LFCR mechanism; but APS would still need to provide facilities to serve 100% of the load sometimes
  - Large lumpy capacity additions eliminate capacity additions for a period of time following the addition; APS models both generating unit additions and purchased capacity to mitigate this effect

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Workshop II (cont.)

Resource Planning & Distributed Energy, Bob Davis (cont.)

- Summary of stakeholder Q&A and general comments:
  - Discussion on timing of avoided costs is compelling; APS can only include actual costs in rate making, for example, future costs escalators in contracts cannot be monetized for rates today
  - ELCC is a rigorous way of looking at resource need
  - Economic benefits of solar orientation and single axis tracking is minimal
  - Surplus DE can help improve system reliability and mitigate loss of generating assets (example is nuclear unit in CA)
  - Stakeholders and APS disagree on whether to model "lumpy" capacity additions

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Workshop II (cont.)

APS Resource Planning, Paul Smith, APS

- Review of APS future load growth and generating capacity need (2017)
- Solar DE energy value simulated using PROMOD IV
  - Detailed simulation of APS costs of generation dispatch
  - Total APS energy costs with and without solar DE
  - Operational challenges can occur during low load periods (ramp up, ramp down, scheduling for dual peaks, increased unit starts, intermittency, dump energy)
  - Integration costs
  - Predominant avoided energy is CC energy
- Key changes from 2009 RW Beck Study
  - APS load forecast (lower)
  - Solar DE implementation (higher)
  - Fuel prices, especially natural gas (lower)
  - CO2 prices (lower)
  - Capacity cost of new CT (higher)
  - Fixed O&M of new CT (higher)
  - NG reservation fee (higher)

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Workshop II (cont.)

APS Resource Planning, Paul Smith (cont.)

- Dependable solar DE capacity based on ELCC analysis
  - Industry best practice methodology
  - Probabilistic - solar DE capacity established over many peak hours not just peak hour
  - Dependable capacity decreases with increasing solar DE implementation
  - Incremental capacity value of future solar DE installations will be significantly less than value today

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Workshop II (cont.)

APS Resource Planning, Paul Smith (cont.)

- Review of additional data considerations
  - APS considerations
    - Must accrue real, measurable benefits to our customers
    - Impacts must be recognized in cost of service ratemaking
    - Test year versus future looking
    - Does not include societal benefits/externalities
  - Market price mitigation
    - Direct cost savings included in PROMOD modeling, indirect value is theoretically possible
    - NG market influence unclear
    - APS not in an LMP market
    - APS is both buyer and seller, uncertain net effect

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Workshop II (cont.)

APS Resource Planning, Paul Smith (cont.)

- Review of additional data considerations
  - Grid security
    - Already addressed by ELCC analysis
  - Fuel hedge value
    - APS models forward price for NG (captures market view)
    - APS has 3-year hedge program (volatility diminished beyond 3-years)
  - Environmental compliance savings
    - Already included in PROMOD simulation
- Review of additional data considerations (cont.)
  - Reliability benefits
    - Spinning and operating reserves already model in PROMOD
    - Solar DE can increase requirements for ancillary services (ignored in APS analysis)
  - Avoided RPS purchases
    - No value above compliance
    - Value only for the net cost of RPS above conventional resources

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Workshop II (cont.)

APS Resource Planning, Paul Smith (cont.)

- Summary of stakeholder Q&A and general comments:
  - Diminishing value of solar DE capacity is produced as the system peak is pushed later in the day
  - Solar DE currently represents a small portion of the APS peak
  - New technologies (e.g., storage) may address some of the issues with diminishing capacity value; APS should consider only short-term forecasts, regular updates
  - Market price mitigation, even if small, should not be zero
  - APS is a net buyer of market energy
  - Emission savings are modeled as sensitivity cases in the IRP
  - Southwest/west orientation provide increased capacity value

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Workshop II (cont.)

Stakeholder comments on initial draft of Cost Benefit Matrix

- Civic awareness should be added to the matrix
- Grid security should be added to the matrix
- Planning horizon with respect to new technologies is a challenge

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Workshop III
SAIC Model and Other Studies
April 11, 2013

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Workshop III

- Introduction of Bob Davis replacing Mark Gabriel as Workshop Facilitator
- Workshop Opening and Review of Workshop II
- Alignment, Bob Davis
  - Difficult alignment process is replaced with Cost Benefit Matrix
  - Will allow workshop participants to identify areas of agreement and disagreement
  - Categories and proposed descriptions were presented
  - Group of volunteers task with adding stakeholder perspectives to the matrix
- Summary of Stakeholder Q&A and comments:
  - The matrix will be presented in the final report
  - Suggestion to add Technology Synergies to the matrix
  - There are additional benefits for solar water heating

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Workshop III (cont.)

- Energy Subsidies, Bob Davis
  - Topic of subsidies originated from discussion of retail rate subsidies
  - Presentation on Federal subsidies for the electricity industry
  - State-specific data difficult to develop/obtain
  - Summary of Stakeholder Q&A and general comments:
    - All fuel sources should be considered
    - Workshop participants uncertain how to reflect subsidies in the technical conferences and cost benefit study
    - Subsidies should be added to the Cost Benefit Matrix
    - Total subsidies of $11B are approximately 4% of electric industry gross revenue
    - What are subsidy levels in current APS rates (APS provided in response to data request)
    - C&I solar DE customers provide a reverse subsidy
    - Renewable industries receive large subsidies because they are not yet mature
    - Federal subsidies are not relevant to ACC rate policies
    - Tax subsidy discussion is important; the sun is not taxed, other fossil fuel and generation receive subsidies
    - Renewables and clean technologies would be more competitive if ratepayers paid the true cost of energy from other sources

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Workshop III (cont.)

- Applying DGValuator to Quantify Value of Solar in APS Service Territory, Tom Hoff, Clean Power Research
  - Benchmark DGValuator using SAIC study results
  - Produce range of values for various costs and benefits
    - Value of solar to utility
    - Value of solar to ratepayers and taxpayers
  - Review of other CPR studies
    - Austin Energy
      - Design solar tariff representing utility value of solar
    - PA and NJ MSEIA Study
      - Full value of solar (utility, ratepayers, taxpayers)

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Workshop III (cont.)

Applying DGValuator, Tom Hoff (cont.)

- Methodology
  - Historical irradiation data
  - Utility value of solar
    - Fuel/energy - marginal cost of CCGT
    - Capacity - capital costs for CCGT
    - T&D capacity - average cost of long-run capacity upgrades
    - Environmental compliance - REC price
    - Fuel price hedge - cost to minimize fuel price uncertainty
    - Marginal losses by benefit category
    - Integration costs
    - Solar DE capacity developed using ELCC
  - Ratepayer and taxpayer value of solar
    - Economic development - net increase in jobs/tax revenues
    - Environmental value - future cost of environmental mitigation
    - Security enhancement - value of avoided outages
    - Market price reduction - price elasticity

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Workshop III (cont.)

Applying DGValuator, Tom Hoff (cont.)

- Summary of Stakeholder Q&A and comments:
  - Ratepayers don't pay for all modeled costs and benefits
  - Solar DE acts like a 30-year market price hedge; but utilities don't hedge for 30 years (too expensive); it is a policy question on whether to include hedging value
  - Value of solar for Austin (12.5 ¢/kWh) and MSEIA (30 ¢/kWh) are different based on value categories are included
  - T&D and reliability is examined on a system-wide basis
  - Uncertain how market price reductions apply to AZ; uncertain how to segregate transmission congestion effects from T&D deferrals
  - Market price reductions may affect other off-system sales
  - Funds spent in the local economy may have more economic benefit than funds spent by the utility

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Workshop III (cont.)

SAIC Distributed Energy Model and Analysis, Scott Burnham, SAIC

- 2013 Refresh Study
  - Leverage 2009 Study methodologies
  - Target years 2015, 2020, 2025
- Updated assumptions
  - Depict higher anticipated DE implementation
  - Lower NG prices
  - Lower CO2 prices
  - Lower Load forecast
  - Lower assumed demand and energy losses

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Workshop III (cont.)

SAIC Distributed Energy Model and Analysis (cont.)

- Implementation scenarios
  - Low - Compliance
  - Expected - approximately twice compliance
  - High - approximately 4x compliance
- Avoided costs
  - Avoided energy
  - Avoided generation capacity and associated transmission
  - Deferment of distribution, sub-transmission, and transmission projects

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Workshop III (cont.)

SAIC Distributed Energy Model and Analysis (cont.)

- Preliminary Results:
  - Deferral of distribution projects
    - Insignificant number of distribution feeders can be impacted
  - Deferral of Sub-transmission projects
    - Four projects can be deferred in target years for expected and high scenarios
  - No load-related transmission projects were identified for deferral
  - Avoided generation costs
    - Avoided energy costs (PROMOD) $88M to $290M (low to high case, 2025)
    - Avoided capacity costs $30M to $45M (low to high case, 2025)
    - Avoided transmission interconnection $5M to $8M (low to high case, 2025)
  - Total avoided costs (nominal $)
    - 2015 - 3.2 to 3.5 ¢/kWh
    - 2020 - 6.6 to 8.0 ¢/kWh
    - 2025 - 6.5 to 10.0 ¢/kWh

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Workshop III (cont.)

SAIC Distributed Energy Model and Analysis (cont.)

- Summary of Stakeholder Q&A and comments:
  - Study analyzed the incremental value of new DE installations; existing installations were modeled but value was not computed for existing installations; rate design impacts on existing and incremental installations was not considered in this cost benefit study
  - Natural gas and CO_2 price sensitivities were analyzed
  - Solar DE is modeled as forecast energy and demand impacts (not number of installations), therefore solar DE technology improvements could be captured by the study
  - Actual monitored DE production was used in the study
  - Losses were assumed to be constant and not vary by load or period
  - Reactive power provided by solar DE was not evaluated

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Workshop III (cont.)

SAIC Distributed Energy Model and Analysis (cont.)

- Summary of Stakeholder Q&A and comments:
  - Solar DE defers approximately 1/3 of planned distribution feeder upgrades
  - The PROMOD simulations were based on the latest APS IRP dataset
  - NG fuel price sensitivity is 30% higher, which captures market price increases since the NG price forecast was developed
  - Study evaluated the value of solar DE; the study did not consider the value of storage
  - Solar water heating was not studied; the most dramatic growth is in solar PV; solar water heating will be considered when APS presents its solution
  - Tom Hoff's presentation shows avoided energy costs of 10 ¢/kWh, while the SAIC study shows a value of 3 ¢/kWh; the 3¢ value is consistent with current NG prices and a CC heat rate; uncertain how Mr. Hoff's value is calculated
  - Should the study consider even lower implementation scenarios

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Workshop IV
Other Policy and Valuation Perspectives
May 9, 2013

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Workshop IV

- Workshop Opening
- Cost Benefit Matrix, Bob Davis
  - Latest edits
  - High-level summary of stakeholder perspectives
  - New categories
  - Summary of Stakeholder Q&A and comments:
    - Some DE technologies are missing; suggest adding perspectives for other technologies like solar water heating
    - Ratepayer cross-subsidization category seems one-sided; but definition reflects that subsidization can flow either way
    - Schools may have a unique load profile and rate impacts of DE; encouraged to participate in the cost benefit matrix
    - Ratepayer and consumer interests are important, but difficult to enumerate

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Workshop IV (cont.)

A Perspective on the Benefits and Costs of Solar Distributed Generation for APS, Tom Beach, SEIA/Crossborder Energy

- Study overview
  - How solar DE impacts APS ratepayers
  - Evaluate DE not NEM
  - Use RIM test
  - 20-yr analysis
- Benefits (avoided costs)
  - Generation energy and capacity
  - Ancillary service & capacity reserves
  - Transmission and distribution
  - Environmental
  - Avoided Renewables
- Costs
  - Lost retail revenues
  - DG Incentives
  - Integration costs

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Workshop IV (cont.)

Benefits and Costs of Solar DE, Tom Beach/SEIA

- Assumptions
  - NG price forecast similar to SAIC study
  - Avoided energy costs (Jun-Sep) - CT at 9,400 Btu/kWh
  - Avoided energy costs (other months) - CC at 7,300 Btu/kWh
  - Avoided capacity costs somewhat consistent with SAIC study
  - Ancillary services set to $5/MWh
  - Capacity reserves modeled at 15%
  - Avoided T&D costs set to combination of assumptions from SAIC study and 2009 RW Beck study
  - Environmental costs set equal to APS IRP sensitivity cases
  - Value of avoided RPS based on APS IRP enhanced renewable portfolios
  - DE costs modeled as ~20 ¢/kWh for residential and ~10 ¢/kWh

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Workshop IV (cont.)

Benefits and Costs of Solar DE, Tom Beach/SEIA

- Results (20-yr levelized)
  - Benefits 21.5 to 23.7 ¢/kWh
  - Costs 13.9 to 15.5 ¢/kWh
  - Benefit/cost ratio is 1.54
  - Benefits exceed costs from both residential and commercial classes
- Summary of Stakeholder Q&A and comments:
  - May be more germane to look at only NEM exports
  - Hourly dispatch was not modeled
  - On the APS system, CTs are run only a few hours per day in the summer, CC energy may be a better estimate of on-peak energy costs for APS; but, the energy prices used for the study are generally consistent with the Palo Verde market price
  - Generating capacity is assumed to be avoided in 2013
  - Study is computing the value of a 2013 DE installation and does not consider diminishing value of DE capacity with increased installations

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Workshop IV (cont.)

Benefits and Costs of Solar DE, Tom Beach/SEIA

- Summary of Stakeholder Q&A and comments (cont.):
  - APS costs for ancillary services is about half of the rates that are used in the model
  - ELCC already incorporates the 15% capacity margin
  - When power exported from a DE resource is consumed by a neighbor, the utility does not have to invest in T&D because the power is flowing only a few feet; this is a misconception, DE resources only provide energy and do not provide all of the services provided by the utility; unless the neighbor disconnects from the grid and receives all services from the DE resource, the utility is still providing services; DE is diversified, as utilities become more familiar with DE resources, they will plan for fewer resources
  - The study used the 2009 RW Beck study for assumptions for avoided transmission costs because the SAIC study computed no avoided load-related transmission costs
  - Because existing installations are included in the study, shouldn't the historical cost of incentives also be included
  - It is appropriate to include the cost of incentives/rebates since these contribute to the program costs covered by ratepayers

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Workshop IV (cont.)

Benefits and Costs of Solar DE, Tom Beach/SEIA

- Summary of Stakeholder Q&A and comments (cont.):
  - Lost retail revenue is modeled at 19.7 cents, instead of current rates at 15.5 cents; the value represents a 20-year levelized value
  - A net positive value in theory means APS could raze the level of incentives
  - Should avoided capacity be weighted by the allocation of avoided energy to different resource types; it's a matter of debate
  - The market price for Palo Verde represents the price for a firm product, not a product that varies hour to hour
  - The modeled natural gas pipeline reservation fee if 2-3 times higher than what APS actually incurs
  - Solar DE causes a pronounced double peak during non-summer days , which will impact the types of resources that APS needs to install to manage this load shape
  - Future storage technologies may positively impact the situation as well

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Workshop IV (cont.)

Creating a Sustainable Solar Market, Chris Yunker, SDG&E

- SDG&E is creating a market structure that can accommodate market changes and customer choices for unbundled services
  - 33% renewable energy by 2020
  - Solar matches peak today, but will change and SDG&E need price signals to incentivize to meet the change
  - At 20% renewable, SDG&E already has surplus during some periods and must sells at a loss
  - Need rates and market structure to incentivize flexible capacity
  - Testing experimental EV and TOU rates
- Intermittent resources
  - Diversity is not sufficient to mange intermittency of renewable resources
  - Need to establish rate incentivizes for storage
  - Customers can buy service from the utility or install it themselves

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Workshop IV (cont.)

Creating a Sustainable Solar Market, Chris Yunker (cont.)

- Unbundled services
  - Technology will cause customers to "unbundle" their needs
  - Utility must provide the correct unbundled price signals
  - Customers should pay a the correct rate when receiving a service and should be compensated at the correct rate when providing a service
  - Correct pricing should have nothing to do with subsidies needed to achieve policy goals
- Summary of Stakeholder Q&A and comments:
  - Since things are always changing, how can solutions be developed today; if prices and services are properly unbundled, they are flexible and can adapt to change
  - How do you make sure incentives are at the right level; incentives and rates should be transparent and unbundled; incentives created through rates are biased
  - Unbundled rates can be too complex for customers to understand; flat rate options can be offered that incorporate a hedge the customer pays

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Workshop IV (cont.)

The Evolution of Net Metering, Rate Design and the Utility Business Model, Ron Binz, Public Policy Consulting

- Policy Objectives
  - Encourage solar
  - Diversify supply
  - Reinforce grid
- Rate design issues
  - Correct signal when price = marginal cost
  - But MC doesn't correctly compensate utility
  - Rate structure compromise
  - Complicated when customer is buyer and seller
- Unbundle tariff rate from DE payment (buy-all/sell-all model)
- Real issue is the evolving utility model, not distribution cost recovery under NEM

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Workshop IV (cont.)

The Evolution of Net Metering, Rate Design and the Utility Business Model, Ron Binz (cont.)

- Utilities 2020
  - Utilities under pressure to change
  - Regulation may not be up to the task
  - Interviews with utility CEOs
    - Want clear energy policies
    - Little incentive for innovation
    - Certainty on climate change policy
  - Interviews with Commissioners
    - Primary focus is rates
    - Open to changing model, but inadequate resources
    - Dissatisfied with process and system
  - New regulatory models

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Workshop IV (cont.)

The Evolution of Net Metering, Rate Design and the Utility Business Model, Ron Binz (cont.)

- Summary of Stakeholder Q&A and comments:
  - Solar has passed break-even threshold with natural gas
  - Long-run incremental cost is the most useful indicator for valuing capacity decisions
  - Accommodating customer choice and flexibility may require changing regulatory model from lowest cost to highest value

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Workshop IV (cont.)

APS Conceptual Solutions, Chuck Miessner (cont.)

- Summary of Stakeholder Q&A and comments (cont.):
  - Customers are not billed at marginal costs, would result in different rates for different customers and may result in high rates
  - In buy-all/sell-all model, how do you project rates/credits over time, do they change simultaneously, how often do they need to be reviewed/set
  - Rates may be changed to remove embedded incentives and administered as a separate tariff
  - One solution under consideration by APS is something similar to the Austin plan
  - Will APS consider eliminating demand charges for schools and churches; this change would make the problem worse
  - Rate fluctuation for DE production makes it difficult to finance DE installations by driving up the cost of finance; rates change over time now, how much stability is needed 5, 10, 20 years
  - Why is net metering being singled out when other cost shifts are not; other subsidy issues are well know and have been vetted through the ACC, net metering and solar DE is not being singled out but instead needs to be vetted similar to the other subsidies

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Workshop IV (cont.)

APS Conceptual Solutions, Chuck Miessner (cont.)

- Summary of Stakeholder Q&A and comments (cont.):
  - APS should consider sending education material on rates to customers applying for solar hookup
  - Marginal costs of new resources are more expensive than the embedded cost/rates, solar DE customers should be awarded for the marginal costs avoided; APS understands and is considering how and if it is possible to reflect future avoided costs through rates
  - Is it better for APS if customers disconnect from the electric system (with appropriate energy production and storage technologies) or continue to be serve through net metering; APS would prefer to have customers so long as costs are being recovered
  - Has APS considered offering rates that provide lower levels of reliability; not in this proceeding
  - Question for financers is what tolerance is needed around rate fluctuation; financing takes fluctuations into account and financers can get comfortable with banded cash flow projections

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Workshop IV (cont.)

APS Conceptual Solutions, Chuck Miessner (cont.)

- Summary of Stakeholder Q&A and comments (cont.):
  - In a buy-all/sell-all model, how do you police solar customers from diverting production prior to the meter
  - What are other utilities doing; Austin is considering separate rates for DE export, SDG&E is considering a more highly unbundled rate structure, Idaho Power is considering treating T&D costs as a demand charge, Dominion Power is implementing standby charges
  - How do we know a future facility will be avoided, what happens if future costs are not avoided but credits have ben provided to DE customers
  - Does PURPA supersede enforcement of a buy-all/sell-all model, don't customers have the choice to sell only the excess; under PURPA, excess is sold at avoided cost, size of the customer and DE facility and annual production also affect the determination; net metering and PURPA are separate rulings
  - Need to consider whether a buy-all/sell-all approach results in tax considerations for the customer that are different than with self-serve and net metering

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Cost Benefit Matrix

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Closing and Final Discussions

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Next Steps

- Meeting notes from Workshop IV have been posted
- Today's presentation has been posted
- Closing Forum meeting notes will be posted by June 7th
- Facilitator's Report will be posted by June 30th
- APS proposed solution filing with ACC in July

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Thank You

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Workshop IV (cont.)

APS Conceptual Solutions, Chuck Miessner (cont.)

- Summary of Stakeholder Q&A and comments (cont.):
  - Customers are not billed at marginal costs, would result in different rates for different customers and may result in high rates
  - In buy-all/sell-all model, how do you project rates/credits over time, do they change simultaneously, how often do they need to be reviewed/set
  - Rates may be changed to remove embedded incentives and administered as a separate tariff
  - One solution under consideration by APS is something similar to the Austin plan
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Workshop IV (cont.)

APS Conceptual Solutions, Chuck Miessner (cont.)

- Summary of Stakeholder Q&A and comments (cont.):
  - APS should consider sending education material on rates to customers applying for solar hookup
  - Marginal costs of new resources are more expensive than the embedded cost/rates, solar DE customers should be awarded for the marginal costs avoided; APS understands and is considering how and if it is possible to reflect future avoided costs through rates
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Workshop IV (cont.)

APS Conceptual Solutions, Chuck Miessner (cont.)

- Summary of Stakeholder Q&A and comments (cont.):
  - In a buy-all/sell-all model, how do you police solar customers from diverting production prior to the meter
  - What are other utilities doing; Austin is considering separate rates for DE export, SDG&E is considering a more highly unbundled rate structure, Idaho Power is considering treating T&D costs as a demand charge, Dominion Power is implementing standby charges
  - How do we know a future facility will be avoided, what happens if future costs are not avoided but credits have ben provided to DE customers
  - Does PURPA supersede enforcement of a buy-all/sell-all model, don't customers have the choice to sell only the excess; under PURPA, excess is sold at avoided cost, size of the customer and DE facility and annual production also affect the determination; net metering and PURPA are separate rulings
  - Need to consider whether a buy-all/sell-all approach results in tax considerations for the customer that are different than with self-serve and net metering

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Cost Benefit Matrix

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Closing and Final Discussions

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Meeting Notes

POWER PUNDITS LLC.

Decision and Process Advisement in Energy and Water

TO: APS Technical Conference Participants

FROM: Power Pundits LLC

RE: Closing Forum Notes

DATE: June 4, 2013

As ordered by the Arizona Corporation Commission related to its 2013 Renewable Energy Standard Implementation Plan, Arizona Public Service Company is conducting a multi-session Technical Conference with stakeholders to evaluate the costs and benefits of distributed renewable energy and net metering. The sessions are designed to bring together stakeholders holding a wide range of perspectives, experiences, and levels of technical knowledge to evaluate these costs for all customers—both those who have access to distributed energy and those who do not. Sessions are exploring such issues as environmental mandates, changes in generation requirements resulting from adding distributed energy to the generation stack, localized grid impacts, system losses and other relevant topics. APS engaged a team from Power Pundits LLC to lead, moderate, and manage this technical conference.

Meetings in this series included:

- An opening forum, February 21
- A technical workshop on understanding rates and distributed energy (DE) benefits, March 7
- A follow-up stakeholder call March 14
- A second technical workshop on resource planning and distributed energy costs, March 20
- A third workshop to review the SAIC refresh work and discuss other models to valuing distributed resources, April 25
- A fourth workshop focused on policy and valuation perspectives, May 9
- A Closing Forum, documented here, held May 28 at the APS Learning Center in downtown Phoenix

The Closing Forum was designed to summarize what was learned during the previous workshops. The agenda included a recap of the previous workshop sessions.

Forty stakeholders pre-registered for this forum, including nine people who participated via a conference phone connection. More than 50 attended in person. Copies of the agenda and presentation slides are available at www.solarfuturearizona.com. An audio recording of the workshop is also available on the site. These notes are the reflection of Power Pundits staff who participated in the workshop and are not a verbatim record. We believe they accurately reflect the sense of the day's meeting.

- ➢ In these meeting notes, questions, comments and discussion among participants are in bulleted boldface items.
- ➢ Action items are indicated by an arrow.

Welcome and Workshop Overview (SLIDES 1-3)
Bob Davis, from nFront Consulting, welcomed workshop participants to this Closing Forum in the multi-session APS Technical Conference on distributed energy and net metering. He briefly reminded participants of the conference purpose, workshop goals and where we are in the process, and highlighted today's agenda.

Jeff Guldner, APS Senior VP (slide 4) also welcomed participants and thanked everyone on behalf of APS, particularly the company's renewable energy and regulatory teams for their active input into this process. Mr. Guldner noted that these important issues needed to be discussed. He said that at end of day, the utility's filing with the ACC will benefit from these discussions.

Review of Technical Conference (SLIDES 4-74)
Mr. Davis explained that today's presentation is a paraphrase of information and discussion presented at the workshops and is not a summary of the results of the forum. He said a summary is being prepared for the facilitator's report. He asked participants to weigh in on the stakeholder summarizations in the presentation to ensure he "got it right."

Opening Forum (SLIDES 9-18)
Mr. Davis reviewed the purpose, forum and workshop goals for this technical conference (slide 7) and next moved to the Opening forum's goals and process. He reminded participants of the issues, challenges and options identified during the opening forum and discussed the alignment process (slide 10). He highlighted several stakeholder perspectives on the workshop goals and issues raised during the opening forum (slides 11-12). He next briefly highlighted several key points made by Eran Mahrer, from SEPA, in his net metering overview presentation (slides 13-15).

Mr. Davis also briefly summarized the APS perspective provided by Greg Bernosky, from APS (slides 16) and reviewed the topics that would be discussed at future sessions (slide 17). Finally, he shared a summary of stakeholder Q&A and comments raised during the opening forum (slide 18).

- **A participant noted that on slide 18, it would be more accurate to state that SAIC did independent work without input from this group/process.**
- **A participant said the ACC order said to address both costs and benefits and net metering. He said the APS report does not address net metering.**
- **APS staff replied that the Commission directive was to conduct a technical conference. The SAIC report was an initiative by APS included in its process; it was not the process itself. APS staff noted that the utility has expanded this process to include many topics of interest to stakeholders. APS agreed that the SAIC study is not a net metering study; it is a study of DE costs and benefits and is foundational for net metering.**

WORKSHOP 1: Understanding Rates and DE Benefits (SLIDES 19-28)
Mr. Davis reviewed the agenda for Workshop 1. He noted that participants discussed SAIC data sources and that there was a robust Q&A on this planned study (slides 20-21). He briefly summarized the presentation on additional data considerations by Tom Beach (representing SEIA) (slide 22) and

highlighted key components of the utility rate-making presentation by Tony Georgis, from New Gen Strategies and Solutions (slides 23-24). Mr. Davis and summarized the presentation by Charles Miessner on APS rates and the impact of solar DE (slide 25-26). For each presentation, Mr. Davis also summarized the stakeholder Qs&As and comments (slides 24 and 27-28).

- **In discussing how utilities recover costs, a participant suggested that the language on slide 24 be clarified to state that rates are designed to recover current costs; that we are not discussing two sets of costs. An APS representative suggested that there are differences in using a future test year compared to a historical test year and that the different methods arrive at different result. The participant clarified that there is an established relationship between costs and billing parameters and differences in methods but that using either method, rates are designed to recover costs during the period the rate is in effect.**
- **A participant suggested, such as on slides 27 and 28, that comments be organized so that its clear which views are from APS and which statements are from other stakeholders. Mr. Davis explained that he was attempting to reflect the diversity of perspective in this presentation and that the report would reflect a fuller discussion.**
- **A participant noted that concerning the comments on slide 28, since mining entities consume about 10 percent of load, other classes subsidize mines because mines only pay 1 percent of the RES charge. She asked if APS had looked at this and if this is cost-shifting. An APS staff member noted that contributions to the RPS adjustor were not looked at in the Navigant study; they looked at rates and cost recovery. He stated that this issue has been debated and decided by ACC and that it gets reviewed every year by the Commission.**
- **A participant suggested that DE and EE are somewhat convoluted. An APS staff member acknowledged that APS has similar concerns for EE but many more customers can participate in EE. Because of this there is less shifting. He added that EE load reductions are about 5 percent not 70 percent, as can be the case for DE. He said this is a smaller magnitude and that APS will address this issue in other forums.**
- **A participant suggested that solar should be treated like other EE measures.**
- **A participant requested that the text on the billing gap on slide 28 be clarified, noting that he believed it was 9 cents for TOU and 15 cents for residential rates**
- **A participant suggested additional clarity on slide 21, in discussing the value of DE included in the SAIC study. He contends that additional incremental value of avoided capacity should be considered, not just conventional power-plant sized blocks.**
- **A participant asked about the inclusion of the cost of carbon starting in 2019 (slide 28) in the text discussing solar DE acting as a hedge against natural gas. An APS staff member said this was used in the SAIC study and was included. He suggested that both the risk and hedge value must be considered. He said that when a utility adds solar or a conventional plant, there are risks. He noted that APS builds and makes purchases. He explained that with a plant, the risks are with both the capital investment and fuel costs. He said with solar, all the risk is in the capital investment, because there are no ongoing fuel costs. The utility is taking more risk in this capital investment because these costs can change over time as well. For solar, he said, APS is sinking that cost for 40 years. He liked this to the risk of putting all one's investment in a capital project and none in O&M, suggesting that upside down mortgages in AZ were a similar situation.**

- **A participant suggested that impacts from climate change and water use should also be captured in the risk discussion. An APS staff member replied that these are captured in capacity and fuel risk planning. He noted that costs for solar installations are decreasing, saying that buying solar today locks the utility into a more expensive resource than future costs—which are trending lower. If the price goes down tomorrow, this is a financial risk for the utility because it results in an adverse outcome.**
- **An APS staff member explained that businesses have to make choices on how to deal with risks. He likened this to homeowners making choices on insurance, saying you can forego insurance, but this subjects you to the volatility of adverse event and the ensuing financial costs, or you can buy insurance to attenuate that volatility through the cost of the insurance premium. A participant noted that in this case, the risk is to the ratepayer not APS, because the costs are covered in a rate adjustment.**
- Another participant asked about cost models and deregulation, questioning how they can benefit the company. **He said, if the risk is costs decreasing, that's a benefit to ratepayers asking, whose issue are we taking up here?**

WORKSHOP II: Resource Planning and DE Costs (SLIDES 29-47)

Mr. Davis reviewed the status of alignments (slides 30-31). He summarized the presentation by Tom Beach, SEIA/Crossborder Energy, on evaluating the benefits and costs of net energy metering in CA (slides 32-36).

- **A participant suggested that the wording on slide 33 should say, "PG&E has stated a 25-cent subsidy..." because no study was done.**
- **Another participant requested that in the text on the E3 study (slide 33) the rate impact of 0.3 cents be included.**

Mr. Davis next recapped his presentation on resource planning and DE (slides 37-41), Paul Smith's presentation on APS resource planning (slides 42-46) and the introduction of the cost-benefit matrix. For each presentation, Mr. Davis also summarized the stakeholder Qs&As and comments (slides 40-41, 46 and 47).

- **A participant noted that slide 44 does not include that ratepayers have asked APS to develop renewable energy. He referred to a study posted on the solarfuturearizona.com Website and suggested that a column for ratepayers' perspective be added to the cost benefit matrix.**

WORKSHOP III: SAIC Model and Other Studies (SLIDES 48-58)

Mr. Davis began the recap of Workshop III by discussing the previous Alignments work, how that led to the cost-benefit matrix and summarized stakeholder Qs and As and comments (slide 49). He summarized the energy subsidies discussion and highlighted stakeholder Qs and As and comments (slide 50) on that topic.

- **A participant said that damage from coal comes to 17.8 cents/kWh (according to studies from Harvard and Yale), with all inclusive costs at 27 cents/kWh. She suggested that this**

won't address today but over the next few years should be part of the discussion. An APS staff member reflected that externalities and societal benefits are difficult to incorporate in a utility cost-of-service or rate process.

Mr. Davis next reviewed the Applying DGValuator presentation by Tom Hoff, Clean Power Research, who was hired by IREC hired to prepare a study using this methodology (slides 51-53). He noted that it will be available later this summer.

- **A participant commented that slide 53 notes that funds spent in the local economy may have more benefit than funds spent by the utility. She said that APS spends $800 million annually on fuel, with two-thirds of that money going out of state. She said that money spent on solar DE stays in the state's economy and this does provide more economic benefit.**

He also summarized the SAIC DE Model and Analysis presentation by Scott Burnham, SAIC (slides 54-56) and the stakeholder Q&A and comments (slides 57-58) during that session. Mr. Davis stakeholder statements were recorded as they were presented (see slide 57). He clarified that the SAIC study did not consider the existing DE installations, only the incremental additions.

- **A participant noted that on slide 56, the generalized savings should be 10 cents/kWh.**
- **A participant said that the SAIC study showed that while only a handful of distribution circuits would be affected, it amounts to one-third of the of planned distribution work and ensuing costs being eliminated. He suggested that this seems like a larger benefit than is credited.**

WORKSHOP IV: Other Policy and Valuation Perspectives (SLIDES 59-74)

Mr. Davis began the review of Workshop IV with a summary of the progress on developing the cost benefit matrix and the stakeholder comments on this work (slide 60). He next summarized the presentation by Tom Beach, Crossborder Energy, on behalf of SEIA on his perspective on the benefits and costs of solar DE and the stakeholder comments and questions on that presentation (slides 61-65).

- **A participant questioned the assumptions for avoided energy costs shown on slide 62. She suggested that this was a big difference and wondered why combined cycle plants weren't the comparative value when combustion turbine plants are so expensive? The participant suggested that instead of turning on a CT on the hottest day of the year, solar DG would replace this capacity.**
- **An APS staff member explained that the utility weighs a number of factors. He agreed that the CT had a very low capacity factor and DG has a much higher factor (in the 20-percent range). He added that APS sees a lot of solar displacement at other times during the year when energy costs are lower and that this must also be accounted for.**

Mr. Davis summarized a presentation on creating a sustainable solar market, made by Chris Yunker, SDG&E, and the stakeholder questions and comments on that presentation (slides 66-67). He recapped the presentation by Ron Binz, Public Policy Consulting, on the evolution of net metering, rate design and the utility business model and the stakeholder questions and comments (slides 68-70).

- **A participant noted that a lot of progress has been made on the demand side but not much has occurred on the supply side.**

Mr. Davis reviewed the APS conceptual solutions presentation by Chuck Miessner (slides 71-74) and the ensuing participant discussion, summarized on slides 71-74.

- **A participant requested preliminary conclusions, suggesting that the various study approached be lined up so participants would be able to compare them to the big picture.**
- **Another participant clarified that the point on slide 73 was not made "tongue in cheek" as suggested by the laughter in the room during the original discussion. He said the issue is not if customers should disconnect or not. He said that if the value of grid connection is $500, he should pay that; if cost is more than the value, the customer should disconnect.**

Mr. Davis wrapped up the Workshop IV review by turning to the Cost Benefit Matrix (slide 75). He noted the addition of four new categories and several minor additions. He noted the matrix now includes input from the solar stakeholders. He asked participants to review and to make edits today so that this document could be finalized and included in the facilitator's report. He also noted that with this Closing Forum, the Website would also be closing [allowing for the posting of these notes] and that he would be preparing the facilitator's report.

He said highlights from the matrix in general are that we have virtually zero 100-percent agreement. However, he noted that there are several topics that stakeholders generally agree should be included as costs and benefits. The differences are in the calculations and methodologies. It's generally agreed that costs for fuel and purchase power, variable O&M, utility system costs, environmental compliance and program administration should be included.

He said stakeholders have partial agreement on DE capacity value, fixed O&M, line losses, transmission and distribution investments, RES avoided costs, integration costs and PV system orientation. How values are calculated, how deeply do you discount for future installations, whether or not to use future or present value, how you measure and model and what's included and excluded are some of the issues raised by stakeholders on these categories of costs and benefits.

He said there was no agreement among stakeholders among the rest of the categories on the matrix. These include suggestions that ratepayer cross subsidy was an issue, but not a cost-benefit category. He said there is no agreement on how to value water consumption, fuel hedging, ancillary services, market price mitigation, decommissioning costs, and the difference between societal and utility costs, as well as grid security, health effects, non-compliance related environmental effects, economic development and jobs, technological synergies and ratepayer and consumer interests.

- **A participant suggested that it's important for the matrix to include all stakeholder perspectives and that a column for ratepayers' perspective is needed. He added that**

APS commissioned a study that confirmed overwhelmingly that AZ ratepayers support adding renewable even if it's at higher cost.

Mr. Davis questioned who could provide this perspective at this late date in the process. He requested that stakeholders provide references to the most salient report language and he would add some text to the matrix. He also directed participants' attention to a document developed by the solar parties. He said this was a late arrival. He got it on Monday. The document addresses methods these parties believe should be considered by APS, not necessarily costs and benefits. He stated these are important issues. The difficulty is in giving all interested parties the ability to respond. Mr. Davis said this document will be posted on the Website and he will consider it as part of the facilitator report.

- **The solar stakeholders agreed with Mr. Davis' proposal to post this as a separate document and suggested other parties should be free to submit their own views. They said all could go in unedited as a way to expand the discussion to other issues. They said this was not an opportunity for others to respond to the industry's position; that they were not looking for rebuttals.**
- **The AECC noted that they would like to get input from its membership, noting that if they'd been asked to provide a position paper they would have done so.**
- **A participant asked about the facilitator's time constraint on this issue.**

Closing and Final Discussion (SLIDES 76-78)
Mr. Davis said that he needs to wrap this work up by mid June and to wrap up the submission of new information very soon. He said that the Workshop IV meeting notes would be posted soon and that he hoped to get today's notes posted within a week and the facilitator's report completed by June 30. APS plans to provide its proposed solution to the Commission in July and to bring it back to the stakeholders before they file with the ACC.

- **An APS representative noted that this is the close of the technical conference but that the record is not closed for additional input for the Commissioners to consider. He said it remains open for everyone to share new materials with the ACC.**
- **A participant asked if APS would file in one docket or separate dockets. APS staff said they did not yet know. It was suggested that when APS makes its filing a separate docket would be opened**

The meeting ended at 4:15 pm.

STAKEHOLDER ALIGNMENT AND COST-BENEFIT MATRIX

Stakeholder Alignments

The following stakeholder alignments were established during the Technical Conferences.

1. Transparency is critical.
2. Subsidies for all fuel sources should be considered.
3. Studies in addition to the Beck (SAIC) study should be considered.
4. Consumer education is important.
5. There is a need for continued innovation and new approaches.
6. Definition of net metering: *Net metering is a billing mechanism that credits solar system owners for the electricity exported onto the grid. Under the simplest implementation of net metering, a utility customer's billing meter runs backward as solar energy is generated and exported to the electricity grid and forward as electricity is consumed from the grid.*
7. DE rate impacts can occur through behind the meter rate offsets (self-supply) as well as net metering bill credits.
8. APS rates are based on historical test years.
9. DE impacts both costs to serve and revenues collected.
10. DE customers have a unique load profile, benefits and costs.

Cost-Benefit Matrix

Beginning with Workshop I, the workshop participants initiated the development of a list of costs and benefits for consideration when evaluating DE. Separate stakeholder groups provided their unique perspectives on the itemized costs and benefits, creating a matrix of perspectives. The final version of the matrix is presented in the following pages.

Distributed Energy Costs and Benefits Perspectives Matrix

The following table summarizes major categories of costs and benefits, and other factors that may affect the evaluation of distributed energy (DE). These categories have been identified by various stakeholders during the 2013 Technical Conference on DE and net metering as factors that could affect the value of DE. The views of the stakeholders and APS regarding the use of each cost/benefit category in valuing DE are described in the respective columns.

Categories	Definition	Solar Parties Perspective	Solar DHW Perspective	Environmental Stakeholder Perspective	Large Commercial & Industrial Stakeholder Perspective	APS Perspective
Fuel & Purchased Power	Utility costs for fuel and purchased power to serve load.	DE should receive credit for avoiding fuel and purchased power costs according to APS' marginal cost of fuel and purchased power during each hour that DE is exported to the grid. As well, DE may permit APS to increase its off-system sales by reducing the total amount of generation needed to serve load. This and all other avoided costs should be calculated taking into consideration appropriate assumptions for timeframe, discount rate, future natural gas prices, future resource mix, de production categories, de production characteristics, and line losses.	SDHW should receive credit for avoiding fuel and purchased power costs.		AECC acknowledges DE avoids fuel and purchased power cost, but any analysis of DE cost/benefits should also recognize that the DE participant avoids purchasing retail energy (and perhaps capacity) from APS. Gas turbine cycling costs increase on a kWh operated basis because of load following solar production from both a turbine efficiency basis and from the need to purchase more EPNG hourly services for more varied natural gas dispatch.	DE permits APS to avoid current, actual fuel and purchased power costs for each kWh generated by the solar system.
Variable Operations & Maintenance	Utility O&M costs that vary with the amount of energy produced.	DE permits APS to avoid certain variable O&M costs for each kWh generated by the solar system. DE should receive credit for these avoided costs according to APS' marginal cost of fuel and purchased power during each hour that DE is exported to the grid.	SDHW should receive credit for avoiding variable O&M costs.		AECC acknowledges DE avoids variable operations & maintenance cost, but any analysis of DE cost/benefits should be net of any *increases* to operations expense and also recognize that the DE participant avoids purchasing retail energy (and perhaps capacity) from APS. Load following solar generation results in higher O&M costs as more starts are required on cloudy days. The more solar installed the less combined cycle gas plants are required and the more simple cycle aero machines are required at higher heat rates	DE permits APS to avoid certain variable O&M costs for each kWh generated by the solar system.

Categories	Definition	Solar Parties Perspective	Solar DHW Perspective	Environmental Stakeholder Perspective	Large Commercial & Industrial Stakeholder Perspective	APS Perspective
Water Consumption	Utility consumption of water to generate electricity.	Water costs embedded in APS O&M costs are based on long-term water rights, but that water could be sold for much more. The market value of the water should be used, rather than APS' avoided costs. Reducing water consumption may also provide additional societal benefits. DE benefits citizens of Arizona and the Southwest because it helps reduce water consumption in an arid state/region. The societal benefits of water conservation should be considered when evaluating DE, even if these benefits are not credited directly to DE providers through rates. This is especially true in AZ where the ACC is a fourth branch of government and serves a quasi-legislative function, taking into account not just utility costs but effects on the broader society as well.	SDHW DE should receive credit for avoiding water consumption and associated costs.	Water consumption is an issue when conventional plants are curtailed due to water shortages. Solar DE reduces the impact of these curtailment events, thus improving the efficiency of utility operations and reducing fuel and other utility operating costs.	AECC believes this category is captured above under variable operations & maintenance.	DE permits APS to avoid actual water costs associated with energy production and is included in O&M costs above.
Cost of Environmental Compliance	Utility costs of state and federal environmental compliance.	DE should receive credit for avoiding costs of environmental compliance. Review is needed to assure that this is reflected in the O&M costs above. DE should also receive credit for its contribution to avoiding any future environmental compliance costs due to the early retirement of existing resources.	SDHW should receive credit for avoiding costs of environmental compliance.		AECC acknowledges DE has the potential to avoid utility environmental compliance cost, but any analysis of avoided cost of environmental compliance should be net of gas turbine operations and recognize only those cost reductions that are directly attributable to DE and whose savings will persist sufficiently into the future, regardless of changes in regulations/rules. Further, any analysis of DE cost/benefits should also recognize that the DE participant avoids purchasing retail energy (and perhaps capacity) from APS.	DE permits APS to avoid actual environmental compliance cost and is included in O&M costs above. These costs are already included in avoided generation costs.

Categories	Definition	Solar Parties Perspective	Solar DHW Perspective	Environmental Stakeholder Perspective	Large Commercial & Industrial Stakeholder Perspective	APS Perspective
Fuel Hedging	Utility cost of hedging future fuel costs.	DE reduces APS' fuel consumption, and therefore reduces the quantity of fuel purchases that APS must hedge against. Associated cost reductions in APS' fuel hedging program should therefore be credited to DE. Furthermore, by reducing fuel purchases, DE also mitigates future volatility in fuel prices not fully accounted for by APS fuel hedging practices. Thus, DE should be credited for any additional hedging costs that customers are willing to pay beyond current utility hedging practices.		DE also provides a hedge to DE participants against future utility rate increases.	AECC acknowledged above that DE avoids fuel & purchased power costs, a component of which is fuel hedging.	APS does not believe that DE would likely lower the cost of fuel hedging to other APS customers in any meaningful way. To the extent that increased DE production allows APS to avoid purchases of natural gas and wholesale power, these avoided costs are included in the avoided fuel and purchased power category, whether the expected costs are hedged or not. However, increased DE production has no impact on hedge costs or benefits related to the natural gas and wholesale power purchases APS must make to serve non-DE customers, so including an additional benefit for this item would be double-counting the fuel savings.

Categories	Definition	Solar Parties Perspective	Solar DHW Perspective	Environmental Stakeholder Perspective	Large Commercial & Industrial Stakeholder Perspective	APS Perspective
DE Capacity Value (e.g., MW)	A component used in calculating DE costs and benefits. The amount of DE capacity (e.g., MW) that the utility can rely upon to meet peak load requirements and system reliability. May be calculated differently for generation, transmission and distribution.	Capacity value is not a cost or a benefit itself, but rather it is an intermediate component/input needed to calculate avoided generation capacity. Several issues affect capacity value of DE on the APS system, including coincidence with the system peak, and the penetration of DE relative to the system's peak demand. These factors are captured by an effective load carrying capability (ELCC) analysis, which would most appropriately be conducted by an independent third party rather than APS. Capacity value may change as DE penetration increases (assuming no change in load shape), however the timing and magnitude of this change are uncertain. Capacity Value should also reflect DE's Impact on APS' Planning Reserve Margins. DE should be treated as a demand-side resource and should reduce planning reserve margins. Net metered DE is "behind the meter" and reduces peak demand; there is no need to apply a planning reserve margin to demand that does not actually occur. This approach is a common practice among resource planners. It is also consistent with the NERC definition of Net Internal Demand that is used to calculate Planning Reserve Margins.	SDHW incorporates storage and can insure benefits throughout the summer peak demand and also offers winter morning peak demand benefits.		AECC acknowledges that DE possesses a capacity value when DE solar reduces specific peak capacity requirements for APS.	Capacity value of DE on the APS system is affected by several issues, including coincidence with the system peak, and diminishing value with increased saturation of DE. These factors are captured by the effective load carrying capability (ELCC) APS analysis.

Categories	Definition	Solar Parties Perspective	Solar DHW Perspective	Environmental Stakeholder Perspective	Large Commercial & Industrial Stakeholder Perspective	APS Perspective
Generation Capacity ($)	Utility costs of investments in new generating resources and associated facilities or incremental fixed costs of future capacity purchases.	DE should receive credit for avoiding future generating capacity or capacity purchases. DE credit for deferred capacity costs should be incremental and not based on exact timing or size of planned generating additions, since the exact timing and size of resource needs is uncertain and potentially subject to gaming. Reduced capacity needs can be translated into reductions in capacity purchases, ownership stakes in jointly owned plants, or the potential for capacity sales to other utilities and should be considered incrementally. Value should be incremental and not based on timing or size of planned generating additions. DE also provides value to customers by reducing the "lumpiness" of capacity investments thereby mitigating the rate impacts of potential over/underinvestment in supply-side generation resources.	SDHW should receive credit for avoiding future generating capacity or capacity purchases. Value should be incremental and not based on timing or size of planned generating additions.		AECC acknowledges DE avoids some capacity cost, but any analysis of DE cost/benefits should also recognize that the DE participant avoids purchasing capacity from APS.	DE potentially permits APS to defer generation capacity and associated costs.
Fixed Operations & Maintenance Costs	Utility fixed O&M costs and other fixed operating costs associated with an avoided or deferred generating resource (or capacity purchases) that do not vary with the amount of energy produced or sold.	DE should receive credit for avoiding fixed O&M costs of new generating resources. DE should receive credit for avoiding fixed O&M costs of new generating resources consistent with the avoided fuel determination.	SDHW should receive credit for avoiding fixed O&M costs of new generating resources.		AECC acknowledges that DE avoids some fixed operations & maintenance costs for those specific utility generation units whose construction is avoided by DE. Any analysis of DE cost/benefits should also recognize that the DE participant avoids purchasing energy (and capacity) from APS.	DE potentially permits APS to defer fixed O&M costs.

Categories	Definition	Solar Parties Perspective	Solar DHW Perspective	Environmental Stakeholder Perspective	Large Commercial & Industrial Stakeholder Perspective	APS Perspective
Line Losses	Difference in the amount of electricity generated and the amount available for use by the end consumers. Energy and demand losses that occur on the transmission and distribution systems.	Line Losses is not a cost or a benefit itself, but rather it is an intermediate component/input needed to calculate avoided fuel and purchased power as well as avoided capacity. Line losses vary significantly across the utility system and the time of day. Input assumption for line losses should reflect the marginal system losses occurring during each hour of DE production (rather than the average line losses, which include low losses late at night).			AECC acknowledges DE avoids line losses for the power the DE participant would have purchased from APS had they not implemented DE solar.	DE potentially permits APS to avoid line losses. This should be based on measured system losses. The quantity of energy and capacity produced by DE at the customer site is adjusted upward for an amount of energy and capacity losses on the electric grid prior to computing the value of reduced energy costs and avoided capacity costs. This is already accounted for in the avoided energy and capacity costs.
Transmission System Investment	Electrical infrastructure used to transmit power from supply sources to the utility's local distribution grid. Investments in transmission infrastructure that are needed to meet future load growth, system expansion, or to assure system reliability.	DE should receive credit for avoiding incremental transmission system costs. This analysis should consider potential for targeted DE system placement with transparency into the need for future system upgrades	SDHW should receive credit for avoiding incremental transmission system costs.		AECC acknowledges DE has the potential to reduce some transmission system investment, but that any transmission investment required to satisfy standby/supplemental loads associated with DE customers must be fully integrated in the cost/benefit analysis. Any analysis of DE cost/benefits should also recognize that the DE participant may avoid purchasing some transmission service from APS.	DE at very high penetration levels may defer future transmission and interconnection costs. Many factors must be considered in this evaluation.
Distribution System Investment	Electrical infrastructure used to distribute power from the transmission system to the consumer. Investments in distribution system infrastructure that are needed to meet future load growth system expansion, or to assure system reliability.	DE should receive credit for avoiding incremental distribution system costs. This analysis should consider potential for targeted DE system placement with transparency into the need for future system upgrades.	SDHWE should receive credit for avoiding incremental distribution system costs.		AECC acknowledges DE has the potential to reduce some distribution system investment to the extent peak system requirements are reduced, but that any distribution investment required to satisfy standby/supplemental loads associated with DE customers must be fully integrated in the cost/benefit analysis. Any analysis of DE cost/benefits should also recognize that the DE participant may avoid purchasing some distribution service from APS.	DE at very high penetration levels may defer future distribution costs. Distribution facilities that can be avoided are limited because facilities must still be sized to meet the peak electric load of the customer which is typically not reduced by DE.

Categories	Definition	Solar Parties Perspective	Solar DHW Perspective	Environmental Stakeholder Perspective	Large Commercial & Industrial Stakeholder Perspective	APS Perspective
Ancillary Services	Electric power related services necessary to support the reliable operation of the electric system (scheduling & dispatch; reactive power & voltage control; loss compensation; load following; system protection; energy imbalance).	For clarity, we suggest that this category be combined with the Integration Cost category below. DE may increase requirements from some ancillary services such as regulating reserves, thus increasing utility operating costs. Black & Veatch recently completed a study for APS quantifying these costs. DE should also receive credit for reducing certain ancillary service costs. For example, modern PV inverters can provide VAR support. Upcoming IEEE 1547 revisions will allow DE to utilize its grid-stabilizing capabilities (reactive power & voltage control, etc.) Future integration costs should also be evaluated for a scenario in which APS has implemented low-cost variable energy integration practices such as those identified in a recent report by the Western Governors' Association.[i]	SDHW facilities may decrease costs for certain ancillary services.	The impact of DE on APS requirements for ancillary services should be empirically analyzed to determine costs or credits assigned to DE.	When DE produces a reduction in the amount of ancillary services required, AECC believes that benefit should be considered in the APS analysis. Any analysis of DE cost/benefits should also recognize that the DE participant may avoid purchasing some ancillary services from APS and that DE customers may increase the amount of ancillary services required	DE may increase requirements for some ancillary services such as regulating reserves, thus increasing utility operating costs. Black & Veatch recently completed a study for APS quantifying these costs.
RES Avoided Costs	Costs for purchasing renewable energy to meet ACC RES requirements.	DE helps meet the APS RES requirements and should get credit for any above-market RES compliance costs.	SDHW helps meet the APS RES requirements and should get credit for avoided RES costs.		AECC believes that no additional credit should be awarded for "avoiding" above-market RES costs, particularly if DE is being subsidized as part of the same RES program.	Any benefit that may exist is limited to the following conditions: 1) if APS is below its RES compliance and 2) renewable power is more expensive than conventional generation. In addition, the value of this potential benefit would be capped at the rates that customers pay for RES programs.

Categories	Definition	Solar Parties Perspective	Solar DHW Perspective	Environmental Stakeholder Perspective	Large Commercial & Industrial Stakeholder Perspective	APS Perspective
Integration Costs	Utility costs to integrate and accommodate new facilities into the electric system. Can include costs for both new required facilities and incremental costs of operation.	For clarity, we suggest that this category be combined with Ancillary Services category above. DE may increase requirements from some ancillary services such as regulating reserves, thus increasing utility operating costs. Black & Veatch recently completed a study for APS quantifying these costs. DE should also receive credit for reducing certain ancillary service costs. For example, modern PV inverters can provide VAR support. Upcoming IEEE 1547a code will allow DE to utilize its grid-stabilizing capabilities (reactive power & voltage control, etc.) Future integration costs should also be evaluated for a scenario in which APS has implemented low-cost variable energy integration practices such as those identified in a recent report by the Western Governors' Association.		DE integration costs should be empirically determined and included in the evaluation of DE.	An empirical matter TBD.	Integrations costs, such as increased costs for ancillary services (see above) and increased costs for customer metering, relaying, and protection should be captured by the APS DE analysis. Including all integration costs will lower the net value of DE.
Administration Costs	Utility costs to administer customer DE adoption including incremental costs for recordkeeping, billing, advertising, and general administration.	Any incremental DE administration costs relative to average customer administration costs are likely to be small, and should be based on reasonable estimates based on availability of smart meters and high penetrations, rather than historic costs with analog meters and fewer facilities.	Any incremental SDHW administration costs are small relative to other program impacts and are not significantly different from average administration costs for non-participating customers.		AECC believes that all administrative program costs associated with DE should be attributed to DG in any cost/benefit analysis	Administration costs and other program costs should be included in the analysis. This would include direct cash incentives as well as rate impacts to other customers. Including all administration costs would lower the net value of DE.

Categories	Definition	Solar Parties Perspective	Solar DHW Perspective	Environmental Stakeholder Perspective	Large Commercial & Industrial Stakeholder Perspective	APS Perspective
Market Price Mitigation	Reduction of wholesale market clearing prices for natural gas and electricity.	To the extent that DE reduces wholesale demand, it may reduce the market clearing prices by shifting the marginal resource to a lower heat-rate generating unit. DE should receive credit for costs avoided by these price reductions.			The capability of DE to reduce wholesale market clearing prices for natural gas and electricity is theoretically possible, but likely to be negligible. Further, so many other factors are in play at the wholesale/regional level that accurately assigning values specific to DE for reducing market wide prices would be highly speculative.	APS does not believe that market price mitigation is a clear benefit. No persuasive analysis has been provided to show that demand reductions related to DE are significant enough to have a measurable impact on wholesale power prices. Wholesale power prices are largely driven by natural gas prices in most hours of the year because natural gas resources are typically the generating units on the margin. Natural gas prices are determined primarily by national and even international factors. Incremental DE is too small to have a measurable effect on national natural gas prices.
PV System Orientation	Changes in DE system value due to specific tilt and azimuth of a system.	PV System Orientation is not a cost or a benefit itself, but is one of several PV Production Characteristics affect the estimated output of PV systems on an hourly basis. These characteristics are inputs to calculating avoided energy and capacity. Southwest orientation may provide more capacity value (more generation when a utility needs it), thus increasing the value of avoided capacity-related costs. Size of system could affect how much energy is exported versus self-supply.			AECC acknowledges that PV system orientation can impact the value associated with a given system's installation type. The value of the orientation of a given DE system should be determined by its hourly output in comparison to utility cost in the same hour.	Orientation of DE systems may affect value. Further, if preferable orientations were provided higher-than-average compensation, then less preferable orientations must be provided lower than average compensation. PV system orientation has largely been determined by customer choice.

Categories	Definition	Solar Parties Perspective	Solar DHW Perspective	Environmental Stakeholder Perspective	Large Commercial & Industrial Stakeholder Perspective	APS Perspective
Grid Security	General reliability of the electric system to transmit power and serve customer loads, especially with respect to the ability to withstand natural or manmade disasters.	DE contributes to grid security by incrementally shifting the resource portfolio towards a large number of small generators. This incrementally reduces the grid's reliance on a small number of large generating units or transmission lines operating simultaneously during a contingency event.	SDHW improves grid security by avoiding the use of electricity during periods when the electricity grid is compromised. Benefits to grid security should be considered and included when computing benefits of DE.		AECC acknowledges DE may provide some benefits with respect to grid security in the event of natural or manmade disasters. DE installations even in high concentrations and at high levels of penetration may still only provide benefits for the installed DE customer and then only for those with defined on-site circuitry that allows them to use island from the utility. The assignment of any value due to "grid security" must be carefully weighed to determine if any benefit can realistically be shared beyond the installed customer.	DE production occurs only during the day, is transient, and is insufficient in scope to meet significant loads of the electric system. As such, DE does not significantly enhance grid security.
Health Effects	DE impact on the use of traditional fossil-fueled generating resources, thus reducing potentially adverse health effects.	The societal benefits of avoided adverse health effects should be considered when evaluating the merits of pursuing more DE, even if these benefits are not credited directly to DE providers through rates. This is especially true in AZ where the ACC is a fourth branch of government and serves a quasi-legislative function, taking into account not just utility costs but effects on the broader society as well (applies to each of the so-called externalities). APS reports that 30% of avoided generation will be from coal plants; if that is assumed, the health benefits of reduced coal generation should be considered.	Benefits of avoided adverse health effects should be considered when computing benefits of SDHW.		AECC acknowledges that DE may avoid harmful emissions from traditional utility generation, which arguably could be counted as benefits in a cost-benefit analysis if the current RES requirement is eliminated; however, if the current RES requirement is retained, the benefits of externalities such as health effects are already implicitly taken into account in the mandated market penetration targets that force the procurement of above-market power. These benefits should not be double counted.	APS believes that the overall assessment of DE in the technical workshop should focus on costs and benefits that directly impact the utility's costs to serve its customers. The key issue that APS has surfaced for the workshops is the potential for a customer with DE to shift the utility's costs to serve them to other customers. Therefore, APS asserts that other "external" costs and benefits that are not recovered through (or have an impact on) retail electric rates, though potentially interesting from a policy standpoint, should not be included in this assessment. The EPA and ADEQ consider health effects when establishing emission control requirements. Avoided capacity costs already account for these environmental costs.

Categories	Definition	Solar Parties Perspective	Solar DHW Perspective	Environmental Stakeholder Perspective	Large Commercial & Industrial Stakeholder Perspective	APS Perspective
Non-compliance Environmental Effects	Environmental effects that are not addressed by utility environmental compliance regulations.	The societal benefits of non-compliance environmental effects should be considered when evaluating the merits of pursuing more DE, even if these benefits are not credited directly to DE providers through rates. This is especially true in AZ where the ACC is a fourth branch of government and serves a quasi-legislative function, taking into account not just utility costs but effects on the broader society as well.	Societal benefits provided by SDHW, such as reduced water use and avoiding pollutants permitted under current regulations should be considered when computing benefits of SDHW.		AECC acknowledges that DE may avoid pollutants, which arguably could be counted in a cost-benefit analysis if the current RES requirement is eliminated; however, if the current RES requirement is retained, the benefits of externalities such as reduced pollution are already implicitly taken into account in the mandated market penetration targets that force the procurement of above-market power. These benefits should not be double counted.	APS believes that the overall assessment of DE in the technical workshop should focus on costs and benefits that directly impact the utility's costs to serve its customers. The key issue that APS has surfaced for the workshops is the potential for a customer with DE to shift the utility's costs to serve them to other customers. Therefore, APS asserts that other "external" costs and benefits that are not recovered through (or have an impact on) retail electric rates, though potentially interesting from a policy standpoint, should not be included in this assessment. The EPA and ADEQ consider environmental effects when establishing emission control requirements. Avoided capacity costs already account for these environmental costs.

Categories	Definition	Solar Parties Perspective	Solar DHW Perspective	Environmental Stakeholder Perspective	Large Commercial & Industrial Stakeholder Perspective	APS Perspective
Economic Development & Jobs	Spurring of local businesses and jobs or industries that contribute to the local economy.	The societal benefits of economic development and jobs should still be considered when evaluating the merits of pursuing more DE, even if these benefits are not credited directly to DE providers through rates. This is especially true in AZ where the ACC is a fourth branch of government and serves a quasi-legislative function, taking into account not just utility costs but effects on the broader society as well.	Benefits of economic development should be considered when computing benefits of DE, including SDHW.	Should be considered as impacts and reported separately from net benefits of DE.	As a component of ratemaking for APS, AECC does not consider economic development & jobs that may result from DE (as compared, it must be assumed, to economic development & jobs from non-DE installation) as an applicable benefits category.	APS believes that the overall assessment of DE in the technical workshop should focus on costs and benefits that directly impact the utility's costs to serve its customers. The key issue that APS has surfaced for the workshops is the potential for a customer with DE to shift the utility's costs to serve them to other customers. Therefore, APS asserts that other "external" costs and benefits that are not recovered through (or have an impact on) retail electric rates, though potentially interesting from a policy standpoint, should not be included in this assessment. The net impact of DE and average electric rates versus other generation sources on local economic development and jobs are an external issue that should not be included in the overall assessment of DE's potential for shifting costs to other customers.
Civic Engagement/ Conservation Awareness	Utility programs may raise public awareness in energy conservation and increase the adoption of other, non-DE, energy conservation programs and measures.	DE should receive credit for any increase in public awareness of energy use that leads to conservation behaviors. This is similar to the approach used by APS in evaluating the spillover effect of its DSM programs. The 2009 California Solar Initiative impact report showed a 7% to 13% usage reduction after customers installed solar energy systems (see table ES-11 of the report).	SDHW DE should receive credit for increasing public awareness and engagement.		As a component of ratemaking for APS, AECC does not consider civic engagement/conservation awareness that may result from DE as an applicable benefits category.	APS does not believe that this is an appropriate benefit of DE for purposes of this evaluation. The costs and benefits of increased participation in other APS energy efficiency programs are already captured in the evaluation and implementation of those programs. In addition, DE programs may very likely reduce participation in DSM programs.

Categories	Definition	Solar Parties Perspective	Solar DHW Perspective	Environmental Stakeholder Perspective	Large Commercial & Industrial Stakeholder Perspective	APS Perspective
Energy Subsidies	Transfer payments, incentives, tax credits, R&D investments, loans, loan guarantees, and other subsidies.	This analysis should consider the costs and benefits of DE apart from any energy subsidies. Separately, there are strong policy justifications to provide incentives offered by electric utilities through programs like APS' DE program, to assure that solar DE receives comparable levels of subsidies as other industries, including accounting for subsidies that other industries have received since their inception.	Sufficient incentives should be provided to solar SDHW, including incentives offered by electric utilities through programs like APS' DE program, to assure that solar SDHW receives comparable levels of subsidies as other industries, including accounting for subsidies that other industries have received since their inception.		AECC opposes increasing solar incentives paid by ratepayers and supports reducing the subsidies paid.	APS does not believe that federal and state tax and spending energy subsidies should be included in this evaluation. These subsidies are federally mandated policies. These energy subsidies impact all rate payers alike and do not result in cost shifting from one customer to another.
Technology Synergies	Applying multiple technologies in a coordinated fashion that yield benefits which are collectively greater than the sum of the benefits from the individual technologies.	Technology Synergies is not a cost or a benefit itself, but rather it is an intermediate component/input needed to calculate avoided capacity costs. DE evaluation should consider scenarios in which technologies and pricing practices can modify the APS load shape sufficiently to move the peak earlier in the day so that it better coincides with solar production. Future load shapes can be managed to minimize costs and requirements for new centralized generation through strategic storage, demand response, and other smart technologies as DE penetration increases. Since non-technology options (such as peak pricing) might accomplish the same effect, we suggest the category be renamed to "Future Load Shape."	SDHW should be evaluated and receives higher credit for capacity for its ability to provide peak demand benefits by avoiding the use of electricity for heating water, especially during the summer months.	Should also take into account technological, installation, siting, organizational, and marketing innovations that have occurred in AZ and, have lowered installed costs, shifted the supply curve for DE downward, shifted the demand curve for DE outward, and increased consumer surplus.	No comment at this time.	Customer programs such as energy efficiency and demand response are designed to reduce load during system peak periods which are typically summer afternoon, and shift it into the late evening or nighttime hours. It would be counter-productive to design customer programs that shift load to the summer afternoons.

Categories	Definition	Solar Parties Perspective	Solar DHW Perspective	Environmental Stakeholder Perspective	Large Commercial & Industrial Stakeholder Perspective	APS Perspective
Decommission-ing Costs	Utility cost to decommission a generating facility at end-of-life.	Decommissioning costs for both DE and avoided new utility generating units should be included in the lifecycle valuation of both technologies. Decommissioning of DE units is largely a customer expense; the only utility costs to consider are removal costs related to any interconnection facilities (paid for by customers) that are no longer useful after the generator is removed.				At a future time, when an avoided CT plant is ready for decommissioning, several factors and market drivers will determine if the plant's salvage value will be less than, equal to, or greater than its cost of decommissioning. Any solar system decommissioning costs should be netted out as well.
Ratepayer/ Consumer Interest	The ACC is required to rule in the interest of ratepayers regarding utility rate structures.	DE provides a social benefit by contributing towards the general energy preferences of the Arizona public as expressed in opinion surveys. This should still be considered when evaluating the merits of pursuing more DE, even if these benefits are not credited directly to DE providers through rates. This is especially true in AZ where the ACC is a fourth branch of government and serves a quasi-legislative function, taking into account not just utility costs but effects on the broader society as well.				The ACC must find that rates are just, reasonable, and in the interests of all customers.
Ratepayer Cross-Subsidization	Higher or lower retail rates experienced by customers that do not participate in a DE program caused by participating customers receiving credits and/or incentives that exceed or underprovide, respectively, the net benefits obtained by the electric utility.	Cross-subsidization is not a cost or benefit itself, but rather it is an aspect of how the costs and benefits are distributed. Cross-subsidization may occur either to or from DE providers depending on how the costs and benefits are calculated.			Higher cost recovery requirements for non-participating customers caused by DE should be eliminated. Rate design updates should be made to remove any subsidies DE customers receive by not paying their actual APS system costs.	A fundamental concept underlying ratemaking is that all customers should pay for the services they receive and subsidization between customer classes should be removed to the extent practical.

Categories	Definition	Solar Parties Perspective	Solar DHW Perspective	Environmental Stakeholder Perspective	Large Commercial & Industrial Stakeholder Perspective	APS Perspective
Generation Capacity ($)	Utility costs of investments in new generating resources and associated facilities or incremental fixed costs of future capacity purchases.	DE should receive credit for avoiding future generating capacity or capacity purchases. DE credit for deferred capacity costs should be incremental and not based on exact timing or size of planned generating additions, since the exact timing and size of resource needs is uncertain and potentially subject to gaming. Reduced capacity needs can be translated into reductions in capacity purchases, ownership stakes in jointly owned plants, or the potential for capacity sales to other utilities and should be considered incrementally. Value should be incremental and not based on timing or size of planned generating additions. DE also provides value to customers by reducing the "lumpiness" of capacity investments thereby mitigating the rate impacts of potential over/underinvestment in supply-side generation resources.	SDHW should receive credit for avoiding future generating capacity or capacity purchases. Value should be incremental and not based on timing or size of planned generating additions.		AECC acknowledges DE avoids some capacity cost, but any analysis of DE cost/benefits shou d also recognize that the DE participant avoids purchasing capacity from APS.	DE potentially permits APS to defer generation capacity and associated costs.
Fixed Operations & Maintenance Costs	Utility fixed O&M costs and other fixed operating costs associated with an avoided or deferred generating resource (or capacity purchases) that do not vary with the amount of energy produced or sold.	DE should receive credit for avoiding fixed O&M costs of new generating resources. DE should receive credit for avoiding fixed O&M costs of new generating resources consistent with the avoided fuel determination.	SDHW should receive credit for avoiding fixed O&M costs of new generating resources.		AECC acknowledges that DE avoids some fixed operations & maintenance costs for those specific utility generation units whose construction is avoided by DE. Any analysis of DE cost/benefits should also recognize that the DE participant avoids purchasing energy (and capacity) from APS.	DE potentially permits APS to defer fixed O&M costs.

Categories	Definition	Solar Parties Perspective	Solar DHW Perspective	Environmental Stakeholder Perspective	Large Commercial & Industrial Stakeholder Perspective	APS Perspective
Utility Systems Costs	Procurement and operating costs for new systems and procedures necessary to manage utility operations in response to DE operations.	DE may add to utility system operation costs, however these costs are already captured above in either Variable O&M or Ancillary Services/Integration. And, newer inverters are likely to reduce utility system costs.			Cost to the utility of additional and changing system protocols and operating routines due to changing demands as well as contingency handling efforts in the event of material swings in available solar DE.	A limited amount of costs to support the administration of APS's DE portfolio are collected annually through the Renewable Energy Standard (RES) budget. Additional facility integration and system operations costs should be captured by the Integration Cost category and will lower the net value of DE.

[i] http://www.westgov.org/component/docman/doc_download/1610-meeting-renewable-energy-targets-in-the-west-at-least-cost-the-integration-challenge-full-report?Itemid=

CATALOG OF WEBSITE DOCUMENTS AS OF JULY 3, 2013

In addition to brief summary information about the technical conference on the site's home page and a page allowing participants to register for meetings, the site contains copies of documents from the Technical Conference sessions on the Meeting Materials page; a variety of documents including stakeholder questions and data requests and answers from APS and several process notices on the Data Room page; and links to or documents from a number of relevant studies and papers on the Studies page.

Meeting Materials Webpage Contents

- Directions to the APS Learning Center
- Directions to the Ocotillo Site
- Opening Forum, February 21, 2013
  - Agenda, Presentations and Meeting Notes
- Workshop 1: Understanding Rates and Distributed Energy Benefits, March 7, 2013
  - Agenda, Presentations, Audio Recording, and Workshop Notes
- Stakeholder Call, March 14, 2013
  - Audio Recording and Call Notes
- Workshop 2: Resource Planning and Distributed Energy Costs, March 20, 2013
  - Agenda, Presentations Rev 4/26, Audio Recording, and Workshop Notes
- Workshop 3: SAIC Study and Other Models, April 11, 2013
  - Agenda, Presentations, SAIC Model and Sensitivity Presentation, Audio Recording, and Workshop Notes
- Workshop 4: Other Policy and Valuation Perspectives, May 9, 2013
  - Agenda, Presentations, Avoided Costs and Benefits Matrix, Audio Recording, and Workshop Notes
- Closing Forum, May 28, 2013
  - Agenda, Presentations, Avoided Costs and Benefits Matrix, Audio Recording, and Meeting Notes

Data Room Webpage Contents

- Solar industry stakeholders' comments on Cost-Benefit Matrix:
  - Solar Parties Comments on Distributed Energy Costs and Benefits Matrix, May 28, 2013
- Stakeholder Data Requests and Q&A:
  - Questions from Vote Solar, February 22, 2013
  - Consolidation of APS Responses to Vote Solar's First Set of Data Requests, March 6,8,12,13 and 14, 2013
  - APS Responses to Vote Solar's Request for Hourly Data in Excel zip file, April 17, 2013
  - Second Set of Questions from Vote Solar, March 14, 2013
  - Consolidation of APS Responses to Vote Solar's Second Set of Data Requests, March 28, April 10 and April 30, 2013
  - Third Set of Questions from Vote Solar, March 25, 2013

- Consolidation of APS Responses to Vote Solar's Third Set of Data Requests, April 4, 10, 12, 16, 23 and 26, 2013
- Vote Solar Initiative's Discovery Request Number 4
- Consolidation of APS Response to Vote Solar's Fourth Set of Data Requests, May 2,8,17 and 21, 2013
- SAIC Study Methodology Suggestion from SEIA, April 2013
- Data Sources for Additional Benefits of Renewable Distributed Energy, Crossborder Energy, March 13, 2013
- Data Request submitted by Edward Burgess, on behalf of IREC, March 13, 2013
- Consolidation of APS Responses to IREC's First Set of Data Request, March 28, April 12, 19 and 26, 2013
- APS Response to IREC's First Set of Data Requests – Flagstaff Systems Hourly Load Data
- IREC's Second Set of Data Requests
- Consolidation of APS Responses to IREC's Second Set of Data Requests, April 23 and 26, 2013
- IREC's Third Set of Data Requests
- Consolidation of APS Response to IREC's Third Set of Data Requests, April 23 and April 26, 2013
- Questions Submitted by Edward Burgess on behalf of IREC, April 26, 2013
- Consolidation of APS Responses to IREC's Fourth Set of Data Requests, May 8 and 28, 2013
- American Solar 1 Questions
- Consolidation of APS Responses to American Solar's First Set of Data Requests, May 8 and 17, 2013

- Data for 2013 Solar PV Value Study:
  - APS 2012 Integrated Resource Plan
  - APS 2013-2017 Renewable Energy Standard Implementation Plan, June 28, 2012
  - APS 2013-2022 Ten-Year Transmission System Plan, January 2013
  - APS Flagstaff Community Power High Penetration Report - Phase 1, Cindi Newman and David J. Narang, APS, September 28, 2011
  - APS Solar Photovoltaic Integration Cost Study, Black and Veatch, November 2012
  - 2013 Photovoltaic Value Study Data in Excel zip files, Rev April 23, 2013

- Process Notices:
  - Joint Exception to Recommended Order Correcting Decision No 73636 Nunc Pro Tunc, March 4, 2013
  - APS Response to Joint Request to Modify Procedural Order, March 6, 2013
  - Notice for March 14, 2013 Stakeholder Call, March 11, 2013
  - Notice of April 23, 2013 Meeting Cancellation, April 22, 2013

Studies Webpage Content

2013

- APS 2013 Updated Solar PV Value Report, SAIC, May 10, 2013
- The Benefits and Costs of Solar Distributed Generation for Arizona Public Service, R. Thomas Beach and Patrick G. McGuire, May 8, 2013
- Vote Solar's Summary of DE Valuation Studies, 2013
- 2013 Conservation in the West: State of the Rockies—Summary Report for Arizona, Colorado College, 2013
- Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System: Study Report in Response to Colorado Public Utilities Commission Decision No. C09-1223, Excel Energy Services, May 23, 2013
- Evaluating the Benefits and Costs of Net Energy Metering in California, R. Thomas Beach and Patrick G. McGuire, Crossborder Energy, January 2013
  - Fact Sheet
  - Full Report
- Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012, VT Public Service Department, January 15, 2013
- Revisiting the Long-Term Hedge Value of Wind Power in an Era of Low Natural Gas Prices, LBNL-6103E, Mark Bolinger, Ernest Orlando Lawrence Berkley National Laboratory, March 2013

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- 2012 Conservation in the West Poll: State of the Rockies—Summary Report for Arizona, Colorado College, 2012
- A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering, Jason B. Keyes and Joseph F. Wiedman, Interstate Renewable Energy Council, prepared for the Solar America Board for Codes and Standards, January 2012
- Literature Review Summary for Vermont Act 125 Evaluation of Net Metering, VT Public Service Department, September 17, 2012
- The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania, Richard Perez, Benjamin L. Norris and Thomas E. Hoff, Clean Power Research, November 2012
- Rewiring California: Integrating Agendas for Energy Reform, Report #214, The Little Hoover Commission, December 3, 2012
- The Economic and Reliability Benefits of CSP with Thermal Energy Storage: Recent Studies and Research Needs, The Concentrating Solar Power Alliance, December 2012

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- Distributed PV: too expensive...or a bargain? Richard Perez, Atmospheric Sciences Research Center, State University of New York at Albany, and Tom Hoff, Clean Power Research, 2011

- APS Informed Perception Project Report, David Daugherty, Erica Edwards, William Hart, Eric Hedberg, Monica Stigler, Christine Totura and Nancy Welch, Morrison Institute for Public Policy, Arizona State University, May 2011
- Key Findings from a Survey of Arizona Voters Regarding Increasing the Use of Renewable Sources for Electricity Purposes, Laura Weigel, Public Opinion Strategies, and David Metz, Fairbanks, Maslin, Maullin, Metz & Associates, March 23, 2011
- Direct Federal Financial Interventions and Subsidies in Energy in FY 2010, US Energy Information Administration, July 2011
- Summary of CPUC Avoided Cost Model: Energy Efficiency Avoided Costs 2011 Update, Brian Horii and Eric Cutter, Energy and Environmental Economics, Inc., December 19, 2011

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- Quantifying the Cost of High-Photovoltaic Penetration, Richard Perez, Atmospheric Sciences Research Center, State University of New York at Albany, Thomas E. Hoff, Clean Power Research, and Marc Perez, Columbia University, paper presented at the 2010 American Solar Energy Society Annual Conference
- The Value of Concentrating Solar Power and Thermal Energy Storage, National Renewable Energy Laboratory Technical Report, NREL-TP-6AZ-45833, Ramteen Sioshansi, The Ohio State University, and Paul Denholm, NREL, February 2010
- Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power, LBNL-2884E, Andrew Miller and Ryan Wiser, Ernest Orlando Lawrence Berkley National Laboratory, September 2010

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- Distributed Renewable Energy Operating Impacts and Valuation Study, R.W. Beck, Inc., January 2009
- An Effective Load Carrying Capability Analysis for Estimating the Capacity Value of Solar Generation Resources on the Public Service Company of Colorado System, Excel Energy Services, February 2009

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- Photovoltaics Value Analysis, National Renewable Energy Laboratory Subcontract Report NREL/SR-581-42303, J. L. Contreras, L. Frantzis, S. Blazewicz, D. Pinault, and H. Sawyer, Navigant Consulting Inc., February 2008
- Power System Planning: Emerging Practices Suitable for Evaluating the Impact of High Penetration Photovoltaics, National Renewable Energy Laboratory Subcontract Report NREL/SR-581-42297, J. Bebic, GE Global Research, February 2008
- Distributed Solar PV Value for Austin Energy, Austin Energy, presented to RMC, September 16, 2008

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- Photovoltaic Capacity Workshop: Developing Consensus on a Capacity Methodology for PV Generation, Richard Perez, State University of New York at Albany, Tom Hoff, Clean Power Research, Mike Taylor, Solar Electric Power Association and JP Ross, Vote Solar Initiative, working paper presented at Solar Power 2007, September 27, 2007

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- The Value of Distributed Photovoltaics to Austin Energy and the City of Austin, Thomas E. Hoff, Richard Perez, Gerry Braun, Michael Kuhn and Benjamin Norris, Clean Power Research, March 17, 2006

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Harris, Tom	PV Advanced Concepts
Held, Josh	Harmon Electric
Higgins, Ben	Mainstream Energy
Higgins, Courtney	Arizona Electric Consumers Council
Hilliker, Curt	Sun Valley Solar Solutions
Ho, Amanda	Arizona Corporation Commission
Hoff, Tom	Clean Power Research
Hogan, Timothy	Arizona Center for Law-Public Interest
Holmes, Dillon	Cambio Energy
Holmes, Morgan	
Holohan, Mark	Wilson Electric
Hoskin, Dan	SmartSolar Solutions LLC
Housley, Andrew	ASU law intern with ACC
Huber, Lon	Next Phase Energy
Huber, Lon	Residential Utility Consumer Office
Jaykumar, Anaisha	Arizona State University
Jennings, Stephen	American Association for Retired People
Johnson, Kate	SolarCity

Name	Organization
Kaszeta, William	Photovoltaic Systems Manufacturing LLC
Keene, Barbara	Arizona Corporation Commission
Kent, Angela	Summerwind Solar
Kern, Jamie	Seabreeze Power Corp.
Keyes, Jason B.	Interstate Renewable Energy Council
King, Dan	Harmon Electric
Koch, Kevin	Technicians For Sustainability
Kohnhorst , Ken	Dependable Solar Products
Kyriss, LaVerne	Power Pundits
LaMora, Eric	Harmon Electric
LaMora, Eric	Harmon Solar
Lamore, Patrick	Arizona Solar Solutions
Lamore, Robert	Arizona Solar Solutions
LaPlaca, Nancy	
Larson, James	US Department of Veterans Affairs
Laudone, Matthew	Arizona Corporation Commission
LeSueur, John	Arizona Corporation Commission
Lind, Michael	REC Solar
Ludgate, Michael	Clean Growth
Luke, Rich	Cambio Energy
MacDougall, Elliott	AZ Solar
Mahoney, Maren	Energy Policy Innovation Council at ASU
Maracas, Kate	Abengoa Solar Inc.
Masson, Milton M.	AriSEIA
Mease, Bob	Residential Utility Consumer Office
Miller, Bryan	Sunrun
Miller, Dean	Lux Consulting
Miller, Mike	EPRI
Miller, Roy	
Mills, Andrew	Lawrence Berkeley National Laboratory
Mirich, Gary	Arizona Electric Consumers Council
Montclair, Ben	IKOLOJI Sustainability Collaborative
Naqvi, Sobia	Abengoa Solar Inc.
Neary, Michael	Arizona Solar Energy Industries Association
Neifert, Robert	Stelcor Energy
Norris, Michael	Scout Solar LLC
Nutting, Meghan	SolarCity
Olek Esler, Margaret	Fennemore Craig, P.C.
Ollarsaba, Federico	Abengoa Solar Inc.
Ormond, Amanda	Interwest Energy Alliance
Pasquinelli, Jeffrey	
Patterson, Greg	Arizona Competitive Power Alliance
Patzer, Russ	Sun Valley Solar Solutions

Name	Organization
Pearce, Tyler	Arizona State University
Perez, Gilbert	Arizona Solar Solutions
Plenk, Bruce	City of Tucson
Polo-Petros, Habib	Polo Electric
Pozefsky, Daniel	Residential Utility Consumer Office
Rauch, Dawson	Kyocera Solar, Inc.
Rauluk, Valerie	Venture Catalyst Inc.
Reed, Peter	Pacific West Solar
Rich, Court	Rose Law Group PC
Rigsby, Bill	Residential Utility Consumer Office
Robertson, Craig	Kyocera Solar
Rogers, C	EchoFirst
Romito, Marc	Tucson Electric Power
Rucker-Holmes, Morgan	Energy Policy Innovation Council
Sanders, Kim	Sunrun
Schlegel, Jeffrey	SWEEP
Schmitt, Karl	Empire Renewable Energy, LLC
Schryver, Ursula	American Association for Retired People
Scott, Maureen A.	Arizona Corporation Commission
Seitz, Joy	American Solar
Seitz, Sean	American Solar
Sheehan, Mike	Tucson Electric Power
Shipley, Bobby C	Buckeye Union High School District
Slaughter, Becky	Yuma Solar
Smith, Jo	Tucson Electric Power
Smith, Joel	Empire Renewable Energy, LLC
Smith, Paul	Arizona Public Service Company
Smith, Kari	Sunpower
Spies, Jeffrey	Quick Mount PV
Stepp, Rex	Arizona Public Service Company
Strite, Sheldon	Cochise Tech and Electric, LLC
Sutton, Geoff	Arizona Solar Center
Sutton, Geoff	Helios Focus
Theisen, Nick	SOLON Corporation
Thomas, Ryan	City of Tucson
Thomason, Heather	Arizona Solar Solutions
Tilghman, Carmine	Tucson Electric Power
Uppal, Joan	Solar Topps LLC
Uppal, Neal	Solar Topps LLC
Van Rensburg, Jaco	EchoFirst
Vaughn, Annie	Natural Power and Energy
Voeller, Steve	Arizona Free Enterprise Club
Wallace, John	Grand Canyon State Electric Coop Assn.

Name	Organization
Wendt, Geoff	Arizona Public Service Company
Wightman, Brett	Abengoa Solar Inc.
Williamson, Ray	Arizona Corporation Commission
Wilson, Ken	Western Resource Advocates
Woodall, Laurie A.	Arizona Corporation Commission
Woods, Larry	Sun City West
Yaquinto, Gary	Arizona Investment Council
Yates, Maura	Sun Edison
Zuckerman, Ellen	SWEEP
Zwick, Cynthia	Arizona Community Action Association