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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 136

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Testimony of Karl R. Rábago
On Behalf of the North Carolina
Sustainable Energy Association

September 27, 2013

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Karl R. Rábago. My business address is 8904 Granada Hills Drive, Austin, Texas.

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

A. I am the principal of Rábago Energy LLC, a Texas limited liability company.

Q. WOULD YOU DISCUSS YOUR EDUCATION AND EXPERIENCE?

A. As to my education, I hold a B.B.A. in management (1977) from Texas A&M University, a J.D. with honors (1984) from the University of Texas School of Law, and LL.Ms in military law (1988) and environmental law (1990) from, respectively, the U.S. Army Judge Advocate General's School and Pace University School of Law. As to my work experience, I served for more than twelve years as an officer in the U.S. Army, including in the Judge Advocate General's Corps and as an assistant professor of law at the United States Military Academy at West Point, New York. I have also worked for more than 20 years in the electricity industry and related fields. I have served as a Commissioner with the Texas Public Utility Commission (1992-1994) and as a Deputy Assistant Secretary for the Office of Utility Technologies with the U.S. Department of Energy (1995-1996). More recently, I have served as Director of Government and Regulatory Affairs for the AES Corporation (2006-2008) and as Vice President of Distributed Energy Services for Austin Energy, a large urban municipal electric utility in Texas. In 2012, I founded and became the principal of Rábago Energy LLC. I also currently serve as Chairman of the Board of Directors of the Center for Resource Solutions (1997-present) and as a member of the Board of Directors of the Interstate Renewable Energy Council (2012-present). My education and work experience is set forth in detail on my resume, attached as **Exhibit KRR-1**.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("COMMISSION") OR OTHER STATE OR FEDERAL BODIES?

A. While I have not previously submitted testimony before the Commission, I have testified under oath before several state regulatory agencies, including the Georgia Public Service Commission, the Louisiana Public Service Commission, and the Michigan Public Service Commission, and before Congress and state legislatures, including most recently the Minnesota State Senate and House of Representatives.

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

A. The electric utilities' proposed 2012 biennial avoided cost rates were filed with the Commission in November of last year. The Public Staff of the North Carolina Utilities Commission ("Public Staff"), the Renewable Energy Group ("REG"), and the North Carolina Sustainable Energy Association ("NCSEA") have asserted, in their pre-hearing comments, that the electric utilities' proposed rates do not accurately represent the electric utilities' "full avoided costs."[1] The purpose of my testimony is to help demonstrate that traditional avoided cost calculations are inadequate to objectively capture the "full avoided costs" associated with solar electric facilities, and that valuation studies and analyses published over the last several years demonstrate this inadequacy with empirical data. I recommend that the Commission address this inadequacy by implementing a short-term and a longer-term approach that will better ensure that "full," non-discriminatory avoided cost rates are offered to qualifying solar electric facilities in both the short-term and the longer-term.

[1] In multiple Commission orders, such as those issued in Dockets E-100, Sub 100 and E-100, Sub 127, this Commission has indicated that the rates it approves must represent the utilities' "full avoided costs."

Q. PLEASE EXPLAIN HOW YOUR TESTIMONY IS ORGANIZED FOR PRESENTATION.

A. I begin my testimony with a brief overview of Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") and the primary purpose of this Commission's biennial proceeding to determine avoided cost rates for electric utility purchases from qualifying facilities. I then speak to the value of solar electric facilities and how traditional avoided cost calculations, such as the "peaker" methodology currently used by this Commission, can fail to adequately capture the "full avoided costs" associated with qualifying solar electric facilities, leading to unintentional but nonetheless impermissible discrimination against qualifying solar electric facilities. Finally, I propose an approach that this Commission can take to more accurately recognize the full avoided costs associated with qualifying solar electric facilities.

OVERVIEW OF PURPA AND PURPOSE OF COMMISSION'S BIENNIAL PROCEEDING TO DETERMINE AVOIDED COST RATES

Q. WHAT IS PURPA?

A. PURPA refers to the Public Utility Regulatory Policies Act of 1978. PURPA is federal legislation that was enacted by Congress and signed into law in 1978. Congress has amended PURPA several times since 1978.

Q. WHAT FEDERAL AGENCY IS CHARGED WITH INTERPRETING PURPA?

A. The Federal Energy Regulatory Commission ("the FERC") is the primary federal agency charged with interpreting and implementing PURPA by making rules and issuing orders.

Q. CAN YOU PROVIDE A BRIEF OVERVIEW OF PURPA AS IT RELATES TO THE AVOIDED COST RATES BEING SET IN THIS PROCEEDING?

A. Yes. In this Commission's 2011 final order in Docket No. E-100, Sub 127, the Commission itself provided an overview of PURPA as it relates to the avoided cost rates being set in this proceeding (I have italicized a portion of the Commission's overview to emphasize it):

> Section 210 of PURPA requires the FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from, and to sell electric power to, cogeneration and small power production facilities. Under Section 210 of PURPA, cogeneration facilities and small power production facilities that meet certain standards and are not owned by persons primarily engaged in the generation or sale of electric power can become qualifying facilities (QFs), and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA. *Each electric utility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration and small power production facilities that obtain qualifying facility status under Section 210 of PURPA. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, are in the public interest, and do not discriminate against cogenerators or small power producers.* The FERC regulations require that the rates electric utilities pay to purchase electric energy and capacity from qualifying cogenerators and small power producers reflect the cost that the purchasing utility can avoid as a result of obtaining energy and

capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers.

Q. GIVEN THE COMMISSION'S OVERVIEW OF PURPA, WHAT IS YOUR UNDERSTANDING OF THE PRIMARY PURPOSE OF THIS PROCEEDING?

A. In this proceeding, I believe the Commission's primary task is setting "full" avoided cost rates which (1) are just and reasonable to the ratepayers of North Carolina's electric utilities, (2) are in the public interest, and (3) do not discriminate against cogenerators or small power producers.

VALUE OF SOLAR ANALYSIS

Q. WHAT IS "VALUE OF SOLAR" ANALYSIS?

A. Value of solar ("VOS") analysis is, in essence, a full avoided cost approach with a long term valuation perspective. Most VOS studies share a common general approach and fairly common general structure. VOS analysis identifies and characterizes the value attributes of distributed solar energy generation in two steps: First, benefits and costs are identified and grouped. Second, the benefits and costs are quantified. Valuation results vary depending on specific methodologies, local energy markets, and other factors, but a growing body of VOS research consistently demonstrates that distributed solar energy has value that significantly exceeds electric utility and ratepayer costs.

Q. GENERALLY, WHAT ARE THE BENEFITS AND COSTS STUDIED IN VOS ANALYSIS?

A. The benefits and costs studied in a VOS analysis are those that accrue to the utility and its ratepayers as a result of meeting demand for electricity services using a distributed solar electric facility rather than the incumbent electric utility's current and planned system resources. These benefits and costs are created when energy generated at the solar facility is generated and consumed over the entire useful life of the facility and are quantified using system average and locationally-specific values associated with displaced utility "system" energy.

Q. CAN YOU IDENTIFY GENERAL CLASSES OR CATEGORIES OF BENEFITS AND COSTS EXAMINED IN VOS ANALYSIS?

A. Yes. At a high level, the benefits and costs studied in VOS analysis fall into the following classes or categories:

- Energy: The basic electrical energy created by the distributed solar electric facility, plus a credit for line-loss savings that accrue because distributed solar displaced generation from remote, central station plants.

- Capacity: Also referred to as "demand." Capacity values capture the avoided capital investments in generation, transmission and distribution that flow from distributed solar generation units.

- Grid support (interconnected operations services): Often referred to as "ancillary services." These benefits include affirmative provision of services and avoidance of costs related to a range of services inherent in maintaining a reliable, functioning grid network. This grid support or ancillary services include, at both the transmission and distribution level, reactive supply and voltage control, regulation and frequency response, energy and generator imbalance, scheduling, forecasting and system control and dispatch.

- Customer benefits: Customers accrue a number of benefits from hosting and operating distributed solar systems including reputational, community participation, bill management and stability, and efficiency support benefits. While some of these benefits do not accrue to the utility, some do, such as the reduced bad debt and delayed payment costs that accompany self-generation.

- Financial and security benefits: These benefits generally reduce both the cost and risk associated with maintaining reliable electric service for customers, especially in the face of variable regulatory, economic, and grid security conditions. These benefits include control of the utility's fuel price volatility and the costs associated with emergency customer power and outages, as well as more rapid and less costly recovery from outage events.

- Environmental benefits: Distributed solar creates benefits in reducing the supply portfolio costs associated with control of criteria pollutants, greenhouse gas emissions, water use, and land use. Where control regimes exist, these costs may be reflected in the cost of operating polluting resources. Distributed solar valuation goes beyond traditional avoided cost approaches in recognizing that these resources also affirmatively reduce financial risks associated with compliance with future control regimes.

- Social benefits: Distributed solar also generates social benefits associated with net job growth benefits compared to "conventional" generation options, increased local tax revenues, reduced occupational safety costs (such as black lung insurance), and others.

Q. EARLIER YOU TESTIFIED THAT A GROWING BODY OF VOS RESEARCH CONSISTENTLY DEMONSTRATES THAT DISTRIBUTED SOLAR ENERGY HAS VALUE THAT SIGNIFICANTLY EXCEEDS THE INCUMBENT ELECTRIC UTILITIES' AND UTILITY RATEPAYERS' COSTS. CAN YOU MORE CLEARLY IDENTIFY THE BODY OF VOS RESEARCH TO WHICH YOU REFERRED?

A. Yes. A representative list of the studies is described in greater detail in attached **Exhibit KRR-2**. The exhibit is a recent report from the Rocky Mountain Institute's ("RMI") eLab Project entitled "A Review of Solar PV Benefit and Cost Studies."

Q. WHAT, IF ANY, CONCLUSIONS HAVE YOU DRAWN FROM YOUR REVIEW OF THE BODY OF VOS RESEARCH?

A. My review of the RMI meta-analysis of the published studies on the value of solar reveals substantial value in each of the categories described above. While the published studies differ in important respects so that they cannot be simply averaged or summed, I reach the following conclusions:

- Studies with more comprehensive analysis discern greater value in a greater number of categories.

- Studies that calculated the levelized value of a stream of benefits and costs associated with solar electric generation over the useful life of the facilities reveal substantially greater value than those using annualized estimates of value. "Snapshot" analyses are highly influenced by current rate, fuel price, and other parameters.

- Studies that internalize planning assumptions that are biased against distributed resource scale and other characteristics systematically underrate the value of distributed solar.

- Studies that quantify risk, such as the risk of fuel price volatility and the risk of environmental regulation, find greater value in solar electric generation, which has little or no risk in these categories.

- Non-utility solar electric generation mitigates significant risk associated with utility-owned facilities, and substantially reduces the net investment cost for generation for all ratepayers.

In sum, based on my review of the RMI analysis and the body of published VOS studies, a comprehensive and unbiased analysis of the benefits and costs of solar electric generation will reveal net value that substantially exceeds the cost to the utility and its ratepayers to stimulate development and use of this resource option.

Q. ARE YOU ASSERTING THAT QUALIFYING SOLAR ELECTRIC FACILITIES IN NORTH CAROLINA ARE CONFERRING NET BENEFITS TO THE ELECTRIC UTILITIES AND THEIR RATEPAYERS?

A. None of the VOS studies used in the RMI analysis or in my analysis were based on specific data from a North Carolina electric utility's service territory. That said, enough research is complete in the United States that general application is reasonable. Given the diversity of the data sets from which the completed VOS studies are drawn, and the relatively high importance of energy costs in the estimation, it is reasonable to conclude that the value delivered by distributed solar generation to North Carolina electric utilities and their ratepayers is comparable to that revealed in the body of VOS research that both RMI and I have analyzed.

Q. YOU STATED THAT NONE OF THE VOS STUDIES YOU USED IN YOUR ANALYSIS WERE BASED ON SPECIFIC DATA FROM A NORTH CAROLINA ELECTRIC UTILITY'S SERVICE TERRITORY. DID YOU SPECIFICALLY EXCLUDE ANY NORTH CAROLINA VOS STUDY RESULTS?

A. No, I did not. I am not aware of any published VOS study results in North Carolina.

Q. DOES THE ABSENCE OF VOS STUDY RESULTS FOR NORTH CAROLINA ALTER YOUR POSITION?

A. No, it does not. It is worth repeating: A strong body of research exists on this topic nationally. The RMI eLab report that I cited earlier and have attached as an exhibit reviews fifteen VOS and other studies addressing distributed solar generation benefits and costs. Among the more prominent researchers, Richard Perez led a team that published a study titled "The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania." That study modeled the value of a 15% peak load penetration of distributed solar electric generation at seven locations in the region. The model addressed the following values:

- Market Price Reduction
- Environmental Value
- Transmission and Distribution Capacity Value
- Fuel Price Hedge Value

- Generation Capacity Value.

The study found that the total value of distributed solar ranged from $0.256 to $0.318 per kWh. I submit this VOS study, attached as **Exhibit KRR-3**, as an indicator of how a comprehensive study can be conducted and the value revealed by such efforts.

Q. ARE YOU AWARE OF ANY VOS STUDY RESULTS FOR SERVICE TERRITORIES IN THE SOUTHEASTERN REGION OF THE UNITED STATES?

A. Earlier this year I served as an expert witness in Georgia's integrated resource planning proceeding. During that proceeding, I became aware that Georgia Power conducted an analysis that relied upon the solar valuation methodology that I used when I worked at Austin Energy. Detailed results of Georgia Power's VOS study are not, to my knowledge, public. Georgia Power attorneys stated on the record that the $0.13 offer price for utility scale solar generation in the company's Advanced Solar Initiative ("ASI") was: (1) higher than the company's traditionally calculated avoided cost, (2) derived with reference to the Austin Energy Value of Solar methodology, and (3) not going to put any upward pressure on rates. I understand that, based at least in part on its internal VOS study findings, Georgia Power is offering certain qualifying solar electric facilities an additional $0.01/kWh (on top of Georgia Power's $0.12/kWh avoided cost offering) to account for the transmission and distribution benefits conferred by distributed solar generation, including avoided transmission, avoided distribution, and avoided line loss.[2] This position is consistent with the results of the work I did on solar valuation in Austin.

VOS AND TRADITIONAL AVOIDED COST METHODOLOGIES

Q. HOW IS VOS ANALYSIS RELEVANT TO THE COMMISSION'S PRIMARY TASK IN THIS PROCEEDING (I.E., SETTING "FULL" AVOIDED COST RATES)?

A. As I stated earlier, VOS studies are, at heart, avoided cost calculations that embrace a full range of costs avoided by distributed solar generation, including savings over the life of the solar generation system. In other words, VOS analysis achieves a better approximation of the "full avoided costs" associated with distributed solar generation. Consequently, VOS studies offer improved market pricing signals over traditional avoided cost calculations, including calculations made under the traditional "peaker" methodology.

Q. WHY DO TRADITIONAL AVOIDED COST CALCULATIONS PROVE INADEQUATE TOOLS FOR CAPTURING THE FULL AVOIDED COSTS ATTRIBUTABLE TO DISTRIBUTED SOLAR GENERATION?

A. Traditional avoided cost calculations evolved at a time when most of the

[2] An excerpt of the transcript for the Georgia proceeding that supports this assertion is attached as **Exhibit KRR-4**.

classes or categories of benefits and costs I mentioned earlier were not as well understood and grid generation was centralized. The calculations were not designed to recognize all of the benefits and costs, such as the full amount of transmission, distribution, and line loss costs avoided by distributed generation. Additionally, the spectrum of viable generation resources has broadened since the traditional avoided cost methodologies were developed. Not all generation resources bear the same risks. Risk is not well addressed in traditional avoided cost methodologies. For example, distributed solar and wind generation may have higher up-front costs, but they do not have ongoing fuel costs, they do not produce emissions, and they are not affected by drought-related water scarcity because they are not steam-driven or water cooled. The higher up-front "capacity" cost essentially eliminates the need to pay for a lifetime of fuel and also eliminates the emissions associated with combusting fuel and all water costs and risks.

Q. DO ANY OTHER FACTORS LIMIT THE RANGE OF BENEFITS AND COSTS REVIEWED UNDER TRADITIONAL AVOIDED COST METHODOLOGIES?

A. Yes. It is important to remember, as I pointed out earlier, that avoided cost estimation derives from the federal PURPA law. The law and the agency that implements it, the FERC, are jurisdictionally limited to power sales and related transactions in the wholesale market. The law and the FERC are not designed or authorized to fully address all of the issues associated with distributed resources that must be reviewed in determining the full extent of costs avoided by a utility when these resources are installed. Only the State commissions can ensure that these benefits and costs are captured properly through state-level implementation of state and federal regulatory law.

Q. DOES THE COMMISSION ENJOY SUFFICIENT AUTHORITY TO REQUIRE THE DEVELOPMENT OF, AND APPROVE THE IMPLEMENTATION OF, A FULL AVOIDED COST FOR SOLAR ELECTRIC GENERATION?

A. Yes. While a VOS analysis would be more comprehensive and support greater accuracy in valuing solar electric generation, the Commission does enjoy considerable authority under PURPA and FERC regulations to require quantification of the full avoided cost for solar electric generation. The FERC has granted broad latitude to states to account for all the costs avoided when electricity from a QF displaces a unit of system electricity. FERC's regulations allow consideration of numerous factors in determining full avoided costs. These factors include, but are not necessarily limited to:

- Reduced line losses;
- Ability to install smaller increments of capacity with shorter lead times;
- Ability to avoid or defer transmission and distribution costs;
- Value of QF capacity and energy;

- Ability to dispatch QF output; the expected or demonstrated reliability of the output; and the usefulness of QF production during system emergencies;
- Environmental benefits and renewable attributes of QF power; and
- Duration and enforceability of QF contracts.[3]

Q. FOR ILLUSTRATIVE PURPOSES, CAN YOU ELABORATE ON THE FUEL PRICE RISK YOU MENTIONED?

A. Yes. A resource that depends on long-term availability of fuel at an affordable price is very different from distributed solar generation, which has no fuel cost, now or in the future. The risk of natural gas price volatility is either ignored or undervalued in the electric utilities' avoided cost calculations. Instead, these costs are passed through annual fuel cost recovery riders, or routinely incurred without robust consideration of resources, like solar, that offer the benefit of reducing these costs. Undervaluing fuel volatility risk causes a generation option like distributed solar generation to seem to avoid less cost than it actually does. The electric utilities' "peaker" approach to avoided cost calculations essentially gives no value to resources that reduce fuel price volatility and instead affirmatively favors resources with low capacity costs, even if the long-run fuel costs for the resource are

[3] The authorization for consideration of these factors, respectively, can be found at: 18 C.F.R. § 292.304(e) (4); 18 C.F.R. § 292.304(e) (2)(vii); 18 C.F.R. § 292.304(e) (3); 18 C.F.R. § 292.304(e) (2)(vi); 18 C.F.R. § 292.304(e) (2)(i); 18 C.F.R. § 292.304(e) (2)(ii); 18 C.F.R. § 292.304(e) (2)(v); *see, e.g., Southern California Edison* , 133 FERC ¶ 61,059 at P 31 ("[I]f the environmental costs 'are real costs that would be incurred by utilities,' then they 'may be accounted for in a determination of avoided cost rates.'"), *rehearing denied*, 134 FERC ¶ 61,044; 18 C.F.R. § 292.304(e) (2)(iii).

variable, difficult to predict, and would require expensive hedging practices to mitigate the volatility risk.

Q. CAN YOU PROVIDE AN EXAMPLE OF WHAT YOU MEAN WHEN YOU SAY "EXPENSIVE HEDGING PRACTICES?"

A. Yes. Each year in its fuel cost recovery rider, Duke Energy Progress, Inc. ("DEP") passes through to customers natural gas hedging costs. Over the past several years, these additional costs amounted to approximately $39 million in 2010, $51 million in 2011 and $70 million in 2012. Even if DEP's hedging practices have changed recently such that it is entering into shorter-term hedges and hedging a smaller percentage of its overall consumption, these changes are offset to a degree by the fact that DEP's overall natural gas consumption is increasing. DEP consumed 72 billion cubic feet ("bcf") of natural gas in 2011-2012, 91 bcf in 2012-2013, and anticipates consuming 158 bcf in 2013-2014. This represents a 100+% increase in overall consumption in a three-year span. While Duke Energy Carolinas, LLC ("DEC") does not currently have a natural gas hedging strategy, it has been ordered to propose a strategy by the end of 2013 and its natural gas consumption has risen from 10 bcf in 2011 to 42 bcf in 2012 and is expected to be 74 bcf in 2013 – a 600+% increase in overall consumption in a three year span. I am not taking issue with the practice of hedging against fuel price volatility, but it is important to note that fuel-free solar electric generation offers true financial and physical hedging benefits to the utility resource portfolio, a value that should be captured in an objective avoided cost estimation process. The data responses which serve as the basis for my answer to this question are attached as **Exhibit KRR-5**.

Q. CAN YOU ELABORATE ON THE WATER COOLING AND ENVIRONMENTAL REGULATION RISKS YOU MENTIONED?

A. Yes. Whether you subscribe to a belief that the climate changes currently being observed are man-made or just part of a planetary cycle, such changes *are being observed* and they introduce a risk of increased generation costs for traditional fleets. Distributed solar generation avoids these potential costs, and importantly, reduces portfolio exposure to the risk of these costs. For example, in Docket No. E-7, Sub 849, DEC indicated it purchased capacity because a drought was causing system deratings and had an impact on power supply. On page 1 of DEC's application in the proceeding, DEC acknowledged that the drought "may be the harbinger of ongoing weather patterns." On page 5, DEC disclosed that it relies on water to, among other things, "[c]ool generating equipment at its . . . combustion turbine power plants." On the same page, DEC disclosed that 70% of its generation capacity at that time was subject to the water levels in just two basins. DEC incurred (and sought immediate recovery for) additional costs when water scarcity became an operational problem for its traditional generation resources. There is significant value in a generation resource that has no exposure to water scarcity over its entire useful life, both on a stand-alone basis and as a component of a generation portfolio. Similarly, DEC's and DEP's recent integrated resource plans indicate that environmental regulations dealing with carbon and other emissions present risks of increased cost. Finally, the development of domestic shale gas plays faces regulatory uncertainty (and a risk of increased costs) in a carbon-constrained future where impacts associated with development are still uncertain and under examination. Distributed solar generation avoids these potential costs.

Q. HOW IS THE OUTPUT OF A QUALIFYING SOLAR ELECTRIC FACILITY VALUED UNDER TRADITIONAL AVOIDED COST METHODOLOGIES?

A. For some of the reasons I have just discussed, distributed solar resources have historically not been offered "full avoided costs" under traditional avoided cost methodologies. Traditionally utilized preferences tend to assign higher value to dispatchable generation options with low capacity cost, while undervaluing several increasingly valuable and important components, such as: fuel price volatility, regulatory (especially environmental) risk, water supply risk, transmission infrastructure requirements, and other risks. Traditional avoided cost methodologies can reduce the value of low- or zero-risk resources and long-run marginal cost and risk reductions.

Q. HOW SHOULD VOS RELATE TO THE PRICE PAID BY AN ELECTRIC UTILITY WHEN IT PURCHASES ELECTRICITY GENERATED BY SOLAR FROM A THIRD PARTY?

A. The VOS should serve as a benchmark for the price an electric utility pays or credits for third-party distributed solar generation. As with the theory behind avoided cost calculation, VOS analysis quantifies the value equal to what it would cost either the utility or a third party to provide solar energy to the point where the energy does its work. It sets an "indifference price" just as avoided cost calculations are intended.

Q. EARLIER, YOU TESTIFIED THAT IT IS REASONABLE TO CONCLUDE THAT THE VALUE DELIVERED BY DISTRIBUTED SOLAR GENERATION TO NORTH CAROLINA ELECTRIC UTILITIES AND THEIR RATEPAYERS IS HIGHER THAN THE COST REQUIRED TO OBTAIN THAT GENERATION. PLEASE EXPLAIN.

A. The electric utilities' proposed avoided cost rates, for both energy and capacity on a composite basis, are in the $0.06/kWh range. Based on the RMI review and my review of the many VOS and other studies, this number undervalues the utilities' "full avoided costs" that are associated with the addition of distributed solar generation. From a review of the filings in this case, there is no evidence that the proposed avoided cost calculations fully quantify the benefits described above, or even approximate the benefits captured by the calculations performed by Georgia Power in the neighboring state of Georgia.[4]

Q. WHAT DOES THIS MEAN IN PRACTICAL TERMS?

A. Earlier I stated that I believe the Commission's primary task in this proceeding is setting "full" avoided cost rates which (1) are just and reasonable to the ratepayers of North Carolina's electric utilities, (2) are in the public interest, and (3) do not discriminate against cogenerators or small power producers. In practical terms, where distributed solar facilities are concerned, the electric utilities' proposed avoided costs are not just and reasonable to the ratepayers. By systematically undervaluing the solar electric generation resource, the utilities are denying ratepayers the benefit of procuring this resource at a cost that will yield substantially greater benefits, including downward pressure on rates, over time. Furthermore, undervaluing solar electric generation discriminates against the small power producers who would otherwise offer this resource into the mix at rates that are just and reasonable to ratepayers. Finally, the systematic undervaluation of solar electric generation under the utility's proposed avoided cost rates is not in the

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[4] Georgia Power is offering certain qualifying solar electric facilities an additional \$0.01/kWh (on top of Georgia Power's \$0.12/kWh avoided cost offering) to account for the transmission and distribution benefits conferred by distributed solar generation, including avoided transmission, avoided distribution, and avoided line loss. For comparison purposes, it appears as though DEC quantified an avoided line loss benefit at \$0.0001/kWh for interconnection to its transmission system and at \$0.0012/kWh for interconnection to its distribution system. Similarly, it appears as though DEP quantified an avoided line loss benefit at \$0.0005/kWh to \$0.0011/kWh. These DEC and DEP figures are derived from attached **Exhibit KRR-6**.

public interest because it promotes suboptimal and economically inefficient investment levels in the solar resource, and by definition leads to overinvestment in second-best resource choices and riskier generation alternatives.

RECOMMENDATION

Q. IN LIGHT OF THE FOREGOING, WHAT IS YOUR VIEW OF THE POSTURE OF THE ISSUES BEFORE THE COMMISSION?

A. DEC and DEP have both acknowledged in a June 10, 2013 filing with the Commission in Docket No. E-100, Sub 137 that a VOS analysis they are conducting may impact avoided cost calculations. The Commission's order scheduling an evidentiary hearing in this proceeding indicated that it was open to re-examining traditional avoided cost methodologies. Thus, the Commission is well positioned to scrutinize and modify the electric utilities' avoided cost methodologies in this proceeding. With that preface, I believe the Commission has several alternatives some of which could be combined over time, for setting "full" avoided cost rates for qualifying solar electric facilities.

Q. WHAT ALTERNATIVES ARE AVAILABLE TO THE COMMISSION TO ADDRESS THE INADEQUACY OF THE ELECTRIC UTILITIES' PROPOSED AVOIDED COST RATES?

A. Aside from addressing the questions relating to the appropriate cost of a combustion turbine, I believe the Commission has two basic alternatives to address the inadequacy of the electric utilities' proposed rates in the current biennium.

First, based on my review of the filings, REG has provided a *legal* argument for increasing North Carolina's performance adjustment factor ("PAF") for solar from 1.2 to 2.0. REG's discrimination argument is consistent with the Public Staff's own past arguments, in Dockets Nos. E-100, Sub 79 and E-100, Sub 106, that resulted in the PAF for run-of-the-river hydro being set at and remaining at 2.0. My review of VOS studies and analysis provides an additional *equitable* basis for increasing the PAF for solar pending a more comprehensive and precise valuation. While the 2.0 PAF for hydro was designed to serve as a kind of equitable relief for QFs that do not have control over their "fuel" source and therefore otherwise are denied the opportunity to recover full capacity payments, a 2.0 PAF for solar can similarly serve to address the discrimination that qualifying solar electric facilities currently face.[5] If the PAF is set to 2.0 for solar, the utilities' proposed offerings to

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[5] It seems worth noting that an appropriate increase in the PAF for qualified solar electric facilities would not result in unjust or unreasonable payments being borne by ratepayers. As this Commission stated, in the hydro context, on page 19 of its final order in Docket No. E-100, Sub 79: "[U]se of a higher performance factor for these hydro facilities does not exceed avoided costs; it simply changes the method by

solar QFs will better approximate the full avoided costs associated with their facilities.

Second, in the wake of the *Southern California Edison* FERC Order, 134 FERC ¶ 61,044, the Commission could direct that a North Carolina solar avoided cost rate be calculated and made available based on reasonable North Carolina-specific VOS study results. It is my understanding that both DEC and DEP are conducting a VOS analysis. Others are likely conducting or considering North Carolina-specific VOS analyses as well.

Q. GIVEN THE NEAR-TERM ALTERNATIVES, WHAT IS YOUR RECOMMENDATION?

A. Given the growing body of VOS research and Georgia Power's recent recognition of some of the additional value of solar generation in its ASI offering, I believe there is no question that traditional avoided cost calculations, including the calculations used by the electric utilities in this proceeding, are undervaluing the costs avoided by the utilities when distributed solar generation is installed. Consequently, qualifying solar electric facilities face discriminatory rates that do not represent the utilities' full avoided costs. The Commission should address this discrimination in this proceeding. From a very practical viewpoint, I believe a PAF adjustment to 2.0 for solar is the least disruptive way to address the discrimination in this

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which avoided costs are paid. It allows these QFs to operate less in order to receive the full capacity payments to which they are entitled, and this seems appropriate and reasonable considering the limitations on their control of their generation."

proceeding. A PAF adjustment could serve as a near-term <u>and</u> longer-term "fix," but I recognize that, with the advent of VOS analysis, such an adjustment may prove to be too imprecise for the longer-term. For the foregoing reasons, I recommend that the Commission (1) increase the PAF for solar electric generation in this proceeding to 2.0 to make the electric utilities' offerings to distributed solar facilities better approximate full avoided costs, and (2) indicate that the increased PAF is intended as an interim measure and will be re-examined in the 2014 biennial avoided cost proceeding (which will be opened less than a year after the final order is issued in this proceeding), at which time the Commission will determine whether to make permanent any PAF adjustment or to establish a solar-specific avoided cost rate or take other action in light of any North Carolina-specific VOS studies.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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Summary

Nationally recognized electricity industry leader and innovator. Experienced as a utility executive leader and manager, public utility regulatory commissioner, research and development program manager, educator, business builder, federal executive, corporate sustainability leader, consultant, and advocate. Thought leader and practice expert in organizational transformation. Highly proficient in advising, managing and interacting with government agencies and committees, the media, citizen groups, and business associations. Successful track record of working with US Congress, state legislatures, governors, regulators, city councils, business leaders, researchers, academia, and community groups. National and international contacts through experience with Austin Energy, AES Corporation, US Department of Energy, Texas Public Utility Commission, Jicarilla Apache Tribal Utility Authority, Cargill Dow LLC (now NatureWorks, LLC), Rocky Mountain Institute, CH2M HILL, Houston Advanced Research Center, Environmental Defense Fund, and others. Expert in development of new energy markets in renewable energy, green power, and tradable credits, and in helping new market entrants shape new products and services. Skilled attorney, negotiator, and advisor with more than twenty years experience working with diverse stakeholder communities in guiding electricity policy and regulation, emerging energy markets development, clean energy technology development, electric utility restructuring, smart grid development, and the implementation of sustainability principles. Nationally recognized speaker on energy, environment and sustainable development matters. Managed staff as large as 250; responsible for operations of research facilities with staff in excess of 600. Developed and managed budgets in excess of $300 million. Law teaching experience at University of Houston Law Center and U.S. Military Academy at West Point. Trial experience as a Judge Advocate. Post doctorate degrees in environmental and military law. Military veteran.

Employment

Rábago Energy LLC

Principal: July 2012--Present. Solo consulting practice dedicated to providing strategic advice and support to businesses and organizations in the clean and advanced energy sectors. Services include distributed energy business, project, and product development; energy policy development and advocacy; renewable energy product development and market development; strategic and corporate sustainability planning; and government and regulatory affairs support. Additional activities:

- Chairman of the Board, Center for Resource Solutions (1997-present). CRS is a not-for-profit organization based at the Presidio in California. CRS developed and manages the Green-e Renewable Electricity Brand, a nationally and internationally recognized branding program for green power and green pricing products and programs. Past chair of the Green-e Governance Board (formerly the Green Power Board).
- Director, Interstate Renewable Energy Council (IREC) (2012-present). IREC focuses on issues impacting expanded renewable energy use such as rules that support renewable energy and distributed resources in a restructured market, connecting small-scale renewables to the utility grid, developing quality credentials that indicate a level of knowledge and skills competency for renewable energy professionals.
- Of Counsel, Osha Liang, LLP. Osha Liang is an intellectual property law firm with offices in Texas, California, France, and Japan.

Austin Energy – The City of Austin, Texas

Vice President, Distributed Energy Services: April 2009—June 2012. Executive in 8th largest public power electric utility serving more than one million people in central Texas. Responsible for management and oversight of energy efficiency, demand response, and conservation programs; low-income weatherization; distributed solar and other renewable energy technologies; green buildings program; key accounts relationships; electric vehicle infrastructure; and market research and product development. Executive sponsor of Austin Energy's participation in an innovative federally-funded smart grid demonstration project led by the Pecan Street Project. Led teams that successfully secured over $39 million in federal stimulus funds for energy efficiency, smart grid, and advanced electric transportation initiatives. Additional activities included:

- Director, Renewable Energy Markets Association. REMA is a trade association dedicated to maintaining and strengthening renewable energy markets in the United States.
- Membership on Pedernales Electric Cooperative Member Advisory Board. Invited by the Board of Directors to sit on first-ever board to provide formal input and guidance on energy efficiency and renewable energy issues for the nation's largest electric cooperative.

THE AES CORPORATION

Director, Government & Regulatory Affairs: June 2006—December 2008. Government and regulatory affairs manager for AES Wind Generation, one of the largest wind companies in the country. Manage a portfolio of regulatory and legislative initiatives to support wind energy market development in Texas, across the United States, and in many international markets. Active in national policy and the wind industry through work with the American Wind Energy Association as a participant on the organization's leadership council. Also served as Managing Director, Standards and Practices, for Greenhouse Gas Services, LLC, a GE and AES venture committed to generating and marketing greenhouse gas credits to the U.S. voluntary market. Authored and implemented a standard of practice based on ISO 14064 and industry best practices. Commissioned the development of a suite of methodologies and tools for various greenhouse gas credit-producing technologies. Also served as Director, Global Regulatory Affairs, providing regulatory support and group management to AES's international electric utility operations on five continents. Additional activities:

- Director and past Chair, Jicarilla Apache Nation Utility Authority (1998 to 2008). Located in New Mexico, the JAUA is an independent utility developing profitable and autonomous utility services that provides natural gas, water utility services, low income housing, and energy planning for the Nation. Authored "First Steps" renewable energy and energy efficiency strategic plan.

HOUSTON ADVANCED RESEARCH CENTER

Group Director, Energy and Buildings Solutions: December 2003—May 2006. The Houston Advanced Research Center (HARC) is a mission-driven not-for-profit contract research organization based in The Woodlands, Texas. Responsible for developing, maintaining and expanding upon technology development, application, and commercialization support programmatic activities, including the Center for Fuel Cell Research and Applications, an industry-driven testing and evaluation center for near-commercial fuel cell generators; the Gulf Coast Combined Heat and Power Application Center, a state and federally funded initiative; and the High Performance Green Buildings Practice, a consulting and outreach initiative. Secured funding for major new initiative in carbon nanotechnology applications in the energy sector. Developed and launched new and integrated program activities relating to hydrogen energy technologies, combined heat and power, distributed energy resources, renewable energy, energy efficiency, green buildings, and regional clean energy development. Active participant in policy development and regulatory implementation in Texas, the Southwest, and national venues. Frequently engaged with policy, regulatory, and market leaders in the region and internationally. Additional activities:

- President, Texas Renewable Energy Industries Association. As elected president of the statewide business association, leader and manager of successful efforts to secure and implement significant expansion of the state's renewable portfolio standard as well as other policy, regulatory, and market development activities.
- Director, Southwest Biofuels Initiative. Established the Initiative acts as an umbrella structure for a number of biofuels related projects, including emissions evaluation for a stationary biodiesel pilot project, feedstock development, and others.

- Member, Committee to Study the Environmental Impacts of Windpower, National Academies of Science National Research Council. The Committee was chartered by Congress and the Council on Environmental Quality to assess the impacts of wind power on the environment.
- Advisory Board Member, Environmental & Energy Law & Policy Journal, University of Houston Law Center.

CARGILL DOW LLC (NOW NATUREWORKS, LLC)

Sustainability Alliances Leader: April 2002—December 2003. Founded in 1997, NatureWorks, LLC is based in Minnetonka, Minnesota. Integrated sustainability principles into all aspects of a ground-breaking biobased polymer manufacturing venture. Responsible for maintaining, enhancing and building relationships with stakeholders in the worldwide sustainability community, as well as managing corporate and external sustainability initiatives. NatureWorks is the first company to offer its customers a family of polymers (polylactide – "PLA") derived entirely from annually renewable resources with the cost and performance necessary to compete with packaging materials and traditional fibers; now marketed under the brand name "Ingeo."

- Successfully completed Minnesota Management Institute at University of Minnesota Carlson School of Management, an alternative to an executive MBA program that surveyed fundamentals and new developments in finance, accounting, operations management, strategic planning, and human resource management.

ROCKY MOUNTAIN INSTITUTE

Managing Director/Principal: October 1999–April 2002. In two years, co-led the team and grew annual revenues from approximately $300,000 to more than $2 million in annual grant and consulting income. Co-authored "Small Is Profitable," a comprehensive analysis of the benefits of distributed energy resources. Worked to increase market opportunities for clean and distributed energy resources through consulting, research, and publication activities. Provided consulting and advisory services to help business and government clients achieve sustainability through application and incorporation of Natural Capitalism principles. Frequent appearance in media at international, national, regional and local levels. RMI is an independent, non-profit research and educational foundation. Joined the organization to develop the Natural Capitalism research and consulting practice at RMI.

- President of the Board, Texas Ratepayers Organization to Save Energy. Texas R.O.S.E. is a non-profit organization advocating low-income consumer issues and energy efficiency programs.
- Co-Founder and Chair of the Advisory Board, Renewable Energy Policy Project-Center for Renewable Energy and Sustainable Technology. REPP-CREST was a national non-profit research and internet services organization.

CH2M HILL

Vice President, Energy, Environment and Systems Group: July 1998–August 1999. Responsible for providing consulting services to a wide range of energy-related businesses and organizations, and for creating new business opportunities in the energy industry for an established engineering and consulting firm. Completed comprehensive electric utility restructuring studies for the states of Colorado and Alaska.

PLANERGY

Vice President, New Energy Markets: January 1998–July 1998. Responsible for developing and managing new business opportunities for the energy services market. Provided consulting and advisory services to utility and energy service companies.

ENVIRONMENTAL DEFENSE FUND

Energy Program Manager: March 1996–January 1998. Managed renewable energy, energy efficiency, and electric utility restructuring programs for a not-for-profit environmental group with a staff of 160 and over 300,000 members. Led regulatory intervention activities in Texas and

California. In Texas, played a key role in crafting Deliberative Polling processes, which in turn led to electric utility restructuring legislation and the state's Renewable Portfolio Standard. Initiated and managed nationwide collaborative activities aimed at increasing use of renewable energy and energy efficiency technologies in the electric utility industry, including the Green-e Certification Program, Power Scorecard, and others. Participated in national environmental and energy advocacy networks, including the Energy Advocates Network, the National Wind Coordinating Committee, the NCSL Advisory Committee on Energy, and the PV-COMPACT Coordinating Council. Frequently appeared before the Texas Legislature, Austin City Council, and regulatory commissions on electric restructuring issues.

UNITED STATES DEPARTMENT OF ENERGY

Deputy Assistant Secretary, Utility Technologies: January 1995–March 1996. Manager of the Department's programs in renewable energy technologies and systems, electric energy systems, energy efficiency, and integrated resource planning. Supervised technology research, development and deployment activities in photovoltaics, wind energy, geothermal energy, solar thermal energy, biomass energy, high-temperature superconductivity, transmission and distribution, hydrogen, and electric and magnetic fields. Developed, coordinated, and advised on legislation, policy, and renewable energy technology development within the Department, among other agencies, and with Congress. Managed, coordinated, and developed international agreements for cooperative activities in renewable energy and utility sector policy, regulation, and market development between the Department and counterpart foreign national entities. Established and enhanced partnerships with stakeholder groups, including technology firms, electric utility companies, state and local governments, and associations. Supervised development and deployment support activities at national laboratories. Developed, advocated and managed a Congressional budget appropriation of approximately $300 million.

STATE OF TEXAS

Commissioner, Public Utility Commission of Texas. May 1992–December 1994. Appointed by Governor Ann W. Richards. Regulated electric and telephone utilities in Texas. Laid the groundwork for legislative and regulatory adoption of integrated resource planning, electric utility restructuring, and significantly increased use of renewable energy and energy efficiency resources. Appointed by Governor Richards to co-chair and organize the Texas Sustainable Energy Development Council, a public/private council that crafted a blueprint for Texas' development of renewable energy, energy efficiency, and other sustainable energy resources. Served as Vice-Chair of the National Association of Regulatory Utility Commissioners (NARUC) Committee on Energy Conservation. Member and co-creator of the Photovoltaic Collaborative Market Project to Accelerate Commercial Technology (PV-COMPACT), a nationwide program to develop domestic markets for photovoltaics. Member, Southern States Energy Board Integrated Resource Planning Task Force. Member of the University of Houston Environmental Institute Board of Advisors.

LAW TEACHING

Associate Professor of Law: University of Houston Law Center, 1990–1992. Full time, tenure track member of faculty. Courses taught: Criminal Law, Environmental Law, Criminal Procedure, Environmental Crimes Seminar, Wildlife Protection Law. Provided *pro bono* legal services in administrative proceedings and filings at the Texas Public Utility Commission. Launched a student clinical effort that reviewed and made recommendations on utility energy efficiency program plans.

Assistant Professor: United States Military Academy, West Point, New York, 1988–1990. Member of the faculty in the Department of Law. Honorably discharged in August 1990, as Major in the Regular Army. Courses taught: Constitutional Law, Military Law, and Environmental Law Seminar. Greatly expanded the environmental law curriculum and laid foundation for the concentration program in law. While carrying a full time teaching load, earned a Master of Laws degree in Environmental Law. Established a program for subsequent environmental law professors to obtain an LL.M. prior to joining the faculty.

LITIGATION

Trial Defense Attorney and Prosecutor, U.S. Army Judge Advocate General's Corps, Fort Polk, Louisiana, January 1985–July 1987. Assigned to Trial Defense Service and Office of the Staff Judge Advocate. Prosecuted and defended over 150 felony courts-martial. As prosecutor, served as legal officer for two brigade-sized units (approximately 5,000 soldiers), advising commanders on appropriate judicial, non-judicial, separation, and other actions. Pioneered use of psychiatric and scientific testimony in administrative and judicial proceedings.

NON-LEGAL MILITARY SERVICE

Armored Cavalry Officer, 2d Squadron 9th Armored Cavalry, Fort Stewart, Georgia, May 1978–August 1981. Served as Logistics Staff Officer (S-4). Managed budget, supplies, fuel, ammunition, and other support for an Armored Cavalry Squadron. Served as Support Platoon Leader for the Squadron (logistical support), and as line Platoon Leader in an Armored Cavalry Troop. Graduate of Airborne and Ranger Schools. Special training in Air Mobilization Planning and Nuclear, Biological and Chemical Warfare.

Formal Education

LL.M., Environmental Law, Pace University School of Law, 1990: Curriculum designed to provide breadth and depth in study of theoretical and practical aspects of environmental law. Courses included: International and Comparative Environmental Law, Conservation Law, Land Use Law, Seminar in Electric Utility Regulation, Scientific and Technical Issues Affecting Environmental Law, Environmental Regulation of Real Estate, Hazardous Wastes Law. Individual research with Hudson Riverkeeper Fund, Garrison, New York.

LL.M., Military Law, U.S. Army Judge Advocate General's School, 1988: Curriculum designed to prepare Judge Advocates for senior level staff service. Courses included: Administrative Law, Defensive Federal Litigation, Government Information Practices, Advanced Federal Litigation, Federal Tort Claims Act Seminar, Legal Writing and Communications, Comparative International Law.

J.D. with Honors, University of Texas School of Law, 1984: Attended law school under the U.S. Army Funded Legal Education Program, a fully funded scholarship awarded to 25 or fewer officers each year. Served as Editor-in-Chief (1983–84); Articles Editor (1982–83); Member (1982) of the Review of Litigation. Moot Court, Mock Trial, Board of Advocates. Summer internship at Staff Judge Advocate's offices. Prosecuted first cases prior to entering law school.

B.B.A., Business Management, Texas A&M University, 1977: ROTC Scholarship (3-yr). Member: Corps of Cadets, Parson's Mounted Cavalry, Wings & Sabers Scholarship Society, Rudder's Rangers, Town Hall Society, Freshman Honor Society, Alpha Phi Omega service fraternity.

Karl R. Rábago

Selected Publications

"The 'Value of Solar' Rate: Designing An Improved Residential Solar Tariff," Solar Industry, Vol. 6, No. 1 (Feb. 2013)

"A Review of Barriers to Biofuels Market Development in the United States," 2 Environmental & Energy Law & Policy Journal 179 (2008).

"A Strategy for Developing Stationary Biodiesel Generation," Cumberland Law Review, Vol. 36, p.461 (2006).

"Evaluating Fuel Cell Performance through Industry Collaboration," co-author, Fuel Cell Magazine (2005).

"Applications of Life Cycle Assessment to NatureWorks™ Polylactide (PLA) Production," co-author, Polymer Degradation and Stability 80 (2003) 403-419.

"An Energy Resource Investment Strategy for the City of San Francisco: Scenario Analysis of Alternative Electric Resource Options," contributing author, Prepared for the San Francisco Public Utilities Commission, Rocky Mountain Institute (2002).

"Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size," co-author, Rocky Mountain Institute (2002).

"Socio-Economic and Legal Issues Related to an Evaluation of the Regulatory Structure of the Retail Electric Industry in the State of Colorado," with Thomas E. Feiler, Colorado Public Utilities Commission and Colorado Electricity Advisory Panel (April 1, 1999).

"Study of Electric Utility Restructuring in Alaska," with Thomas E. Feiler, Legislative Joint Committee on electric Restructuring and the Alaska Public Utilities Commission (April 1, 1999).

"New Markets and New Opportunities: Competition in the Electric Industry Opens the Way for Renewables and Empowers Customers," EEBA Excellence (Journal of the Energy Efficient Building Association) (Summer 1998).

"Building a Better Future: Why Public Support for Renewable Energy Makes Sense," Spectrum: The Journal of State Government (Spring 1998).

"Preserving the Integrity of Green Markets," Solar Today (May/June 1998).

"The Green-e Program: An Opportunity for Customers," with Ryan Wiser and Jan Hamrin, Electricity Journal, Vol. 11, No. 1 (January/February 1998).

"Being Virtual: Beyond Restructuring and How We Get There," Proceedings of the First Symposium on the Virtual Utility, Klewer Press (1997).

"Information Technology," Public Utilities Fortnightly (March 15, 1996).

"Better Decisions with Better Information: The Promise of GIS," with James P. Spiers, Public Utilities Fortnightly (November 1, 1993).

"The Regulatory Environment for Utility Energy Efficiency Programs," Proceedings of the Meeting on the Efficient Use of Electric Energy, Inter-American Development Bank (May 1993).

"An Alternative Framework for Low-Income Electric Ratepayer Services," with Danielle Jaussaud and Stephen Benenson, Proceedings of the Fourth National Conference on Integrated Resource Planning, National Association of Regulatory Utility Commissioners (September 1992).

"What Comes Out Must Go In: The Federal Non-Regulation of Cooling Water Intakes Under Section 316 of the Clean Water Act," Harvard Environmental Law Review, Vol. 16, p. 429 (1992).

"Least Cost Electricity for Texas," State Bar of Texas Environmental Law Journal, Vol. 22, p. 93 (1992).

"Environmental Costs of Electricity," Pace University School of Law, Contributor–Impingement and Entrainment Impacts, Oceana Publications, Inc. (1990).

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EXHIBIT
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eLab
Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

A REVIEW OF SOLAR PV BENEFIT & COST STUDIES

2nd Edition

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2nd Edition, published September 2013
download at: www.rmi.org/elab_emPower

ABOUT THIS DOCUMENT

e Lab
Electricity Innovation Lab
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This report is a 2nd edition released in September 2013. This second edition updates the original with the inclusion of Xcel Energy's May 2013 study,* Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado, *as well as clarifies select descriptions and charts.

TABLE OF CONTENTS

OBJECTIVE AND ACKNOWLEDGEMENTS

The objective of this e-Lab discussion document is to assess what is known and unknown about the categorization, methodological best practices, and gaps around the benefits and costs of distributed photovoltaics (DPV), and to begin to establish a clear foundation from which additional work on benefit/cost assessments and pricing structure development can be built.

Building on initial research conducted as part of Rocky Mountain Institute's (RMI) DOE SunShot funded project, Innovative Solar Business Models, this e-Lab work product was prepared by RMI to support e-Lab and industry-wide discussions about distributed energy resource valuation. e-Lab is a joint collaboration, convened by RMI, with participation from stakeholders across the electricity industry. e-Lab is not a consensus organization, and the views expressed in this document do not necessarily represent those of any individual e-Lab member or supporting organizations. Any errors are solely the responsibility of RMI.

e-Lab members and advisors were invited to provide input on this report. The assessment greatly benefited from contributions by the following individuals: Stephen Frantz, Sacramento Municipal Utility District (SMUD); Mason Emnett, Federal Energy Regulatory Commission (FERC); Eran Mahrer, Solar Electric Power Association (SEPA); Sunil Cherian, Spirae; Karl Rabago, Rabago Energy; Tom Brill and Chris Yunker, San Diego Gas & Electric (SDG&E); and Steve Wolford, Sunverge.

WHAT IS e-LAB?

The Electricity Innovation Lab (e-Lab) brings together thought leaders and decision makers from across the U.S. electricity sector to address critical institutional, regulatory, business, economic, and technical barriers to the economic deployment of distributed resources.

In particular, e-Lab works to answer three key questions:

- How can we understand and effectively communicate the costs and benefits of distributed resources as part of the electricity system and create greater grid flexibility?
- How can we harmonize regulatory frameworks, pricing structures, and business models of utilities and distributed resource developers for greatest benefit to customers and society as a whole?
- How can we accelerate the pace of economic distributed resource adoption?

A multi-year program, e-Lab regularly convenes its members to identify, test, and spread practical solutions to the challenges inherent in these questions. e-Lab has three annual meetings, coupled with ongoing project work, all facilitated and supported by Rocky Mountain Institute. e-Lab meetings allow members to share learnings, best practices, and analysis results; collaborate around key issues or needs; and conduct deep-dives into research and analysis findings.

EXECUTIVE SUMMARY

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EXECUTIVE SUMMARY

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THE NEED

- The addition of distributed energy resources (DERs) onto the grid creates new opportunities and challenges because of their unique siting, operational, and ownership characteristics compared to conventional centralized resources.

- Today, the increasingly rapid adoption of distributed solar photovoltaics (DPV) in particular is driving a heated debate about whether DPV creates benefits or imposes costs to stakeholders within the electricity system. But the wide variation in analysis approaches and quantitative tools used by different parties in different jurisdictions is inconsistent, confusing, and frequently lacks transparency.

- Without increased understanding of the benefits and costs of DERs, there is little ability to make effective tradeoffs between investments.

OBJECTIVE OF THIS DOCUMENT

- The objective of this e-Lab discussion document is to assess what is known and unknown about the categorization, methodological best practices, and gaps around the benefits and costs of DPV, and to begin to establish a clear foundation from which additional work on benefit/cost assessments and pricing structure design can be built.

- This discussion document reviews 16 DPV benefit/cost studies by utilities, national labs, and other organizations. Completed between 2005 and 2013, these studies reflect a significant range of estimated DPV value.

KEY INSIGHTS

- No study comprehensively evaluated the benefits and costs of DPV, although many acknowledge additional sources of benefit or cost and many agree on the broad categories of benefit and cost. There is broad recognition that some benefits and costs may be difficult or impossible to quantify, and some accrue to different stakeholders.

- There is a significant range of estimated value across studies, driven primarily by differences in local context, input assumptions, and methodological approaches.

    - **Local context**: Electricity system characteristics—generation mix, demand projections, investment plans, market structures—vary across utilities, states, and regions.
    - **Input assumptions**: Input assumptions—natural gas price forecasts, solar power production, power plant heat rates—can vary widely.
    - **Methodologies**: Methodological differences that most significantly affect results include (1) resolution of analysis and granularity of data, (2) assumed cost and benefit categories and stakeholder perspectives considered, and (3) approaches to calculating individual values.

- Because of these differences, comparing results across studies can be informative, but should be done with the understanding that results must be normalized for context, assumptions, or methodology.

- While detailed methodological differences abound, there is general agreement on overall approach to estimating energy value and some philosophical agreement on capacity value, although there remain key differences in capacity methodology. There is significantly less agreement on overall approach to estimating grid support services and currently unmonetized values including financial and security risk, environment, and social value.

EXECUTIVE SUMMARY (CONT'D)

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IMPLICATIONS

- Methods for identifying, assessing and quantifying the benefits and costs of DPV and other DERs are advancing rapidly, but important gaps remain to be filled before this type of analysis can provide an adequate foundation for policymakers and regulators engaged in determining levels of incentives, fees, and pricing structures for DPV and other DERs.

- In any benefit/cost study, it is critical to be transparent about assumptions, perspectives, sources and methodologies so that studies can be more readily compared, best practices developed, and drivers of results understood.

- While it may not be feasible to quantify or assess sources of benefit and cost comprehensively, benefit/cost studies must explicitly decide if and how to account for each source of value and state which are included and which are not.

- While individual jurisdictions must adapt approaches based on their local context, standardization of categories, definitions, and methodologies should be possible to some degree and will help ensure accountability and verifiability of benefit and cost estimates that provide a foundation for policymaking.

- The most significant methodological gaps include:

  - **Distribution value:** The benefits or costs that DPV creates in the distribution system are inherently local, so accurately estimating value requires much more analytical granularity and therefore greater difficulty.
  - **Grid support services value:** There continues to be uncertainty around whether and how DPV can provide or require additional grid support services, but this could potentially become an increasingly important value.
  - **Financial, security, environmental, and social values:** These values are largely (though not comprehensively) unmonetized as part of the electricity system and some are very difficult to quantify.

LOOKING AHEAD

- Thus far, studies have made simplifying assumptions that implicitly assume historically low penetrations of DPV. As the penetration of DPV on the electric system increases, more sophisticated, granular analytical approaches will be needed and the total value is likely to change.

- Studies have largely focused on DPV by itself. But a confluence of factors is likely to drive increased adoption of the full spectrum of renewable and distributed resources, requiring a consideration of DPV's benefits and costs in the context of a changing system.

- With better recognition of the costs and benefits that all DERs can create, including DPV, pricing structures and business models can be better aligned, enabling greater economic deployment of these resources and lower overall system costs for ratepayers.

FRAMING THE NEED

01

overview
distributed energy resources
structural misalignments
structural misalignments in practice

FRAMING THE NEED

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- A confluence of factors including rapidly falling solar prices, supportive policies, and new approaches to finance are leading to a steadily increasing solar PV market.
  - In 2012, the US added 2 GW of solar PV to the nation's generation mix, of which approximately 50% were customer-sited solar, net-metered projects.[1]
  - Solar penetrations in certain regions are becoming significant. About 80% of customer-sited PV is concentrated in states with either ample solar resource and/or especially solar-friendly policies: California, New Jersey, Arizona, Hawaii and Massachusetts.[2]
- The addition of DPV onto the grid creates new challenges and opportunities because of its unique siting, operational, and ownership characteristics compared to conventional centralized resources. The value of DPV is temporally, operationally and geographically specific and varies by distribution feeder, transmission line configuration, and composition of the generation fleet.
- Under today's regulatory and pricing structures, multiple misalignments along economic, social and technical dimensions are emerging. For example, in many instances pricing mechanisms are not in place to recognize or reward service that is being provided by either the utility or customer.
- Electricity sector stakeholders around the country are recognizing the importance of properly valuing DPV and the current lack of clarity around the costs and benefits that drive DPV's value, as well as how to calculate them.
- To enable better technical integration and economic optimization, it is critical to better understand the services that DPV can provide and require, and the benefits and costs of those services as a foundation for more accurate pricing and market signals. As the penetration of DPV and other customer-sited resources increases, accurate pricing and market signals can help align stakeholder goals, minimize total system cost, and maximize total net value.

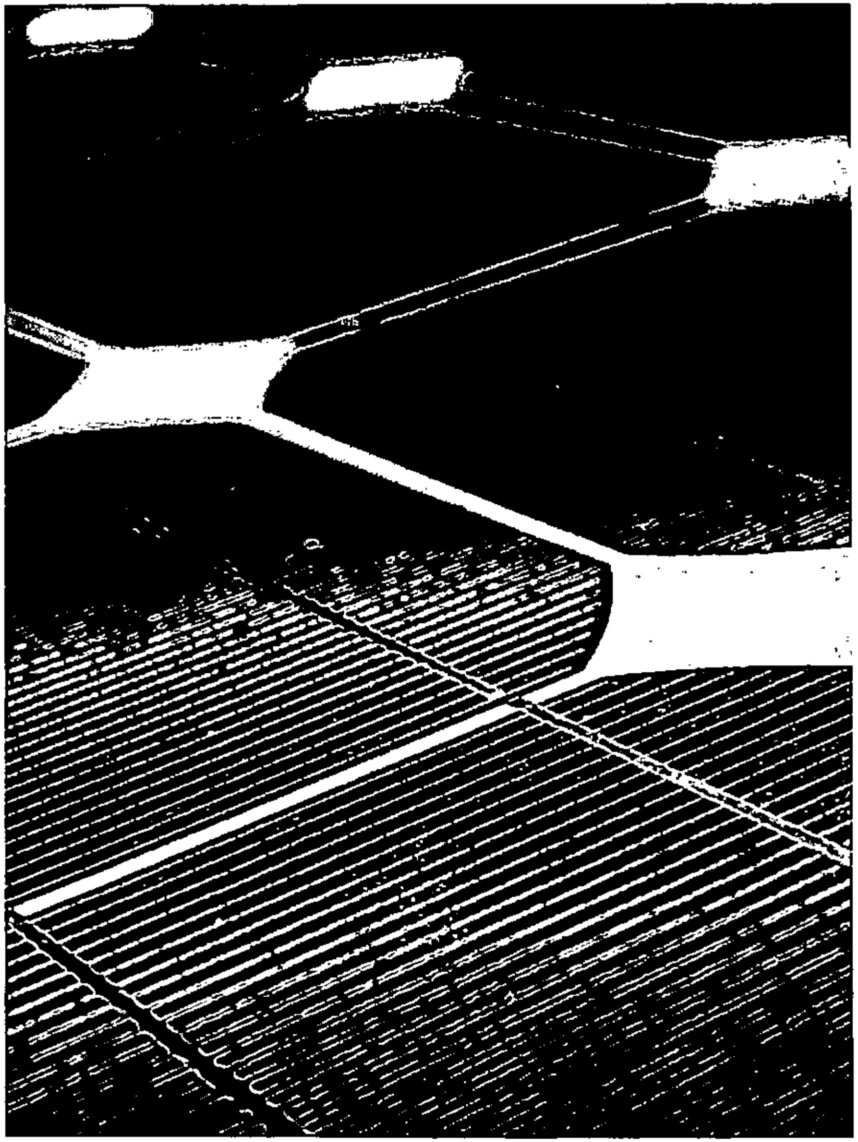

Photo courtesy of Shutterstock

1. Solar Electric Power Association. June 2013. *2012 SEPA Utility Solar Rankings*, Washington, DC.
2. Ibid.

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DPV IN THE BROADER CONTEXT OF DISTRIBUTED ENERGY RESOURCES

DISTRIBUTED ENERGY RESOURCES (DERs): demand- and supply-side resources that can be deployed throughout an electric distribution system to meet the energy and reliability needs of the customers served by that system. DERs can be installed on either the customer side or the utility side of the meter.

TYPES OF DERs:

Efficiency

Technologies and behavioral changes that reduce the quantity of energy that customers need to meet all of their energy-related needs.

Distributed generation

Small, self-contained energy sources located near the final point of energy consumption. The main distributed generation sources are:

- Solar PV
- Combined heat & power (CHP)
- Small-scale wind
- Others (i.e., fuel cells)

Distributed flexibility & storage

A collection of technologies that allows the overall system to use energy smarter and more efficiently by storing it when supply exceeds demand, and prioritizing need when demand exceeds supply. These technologies include:

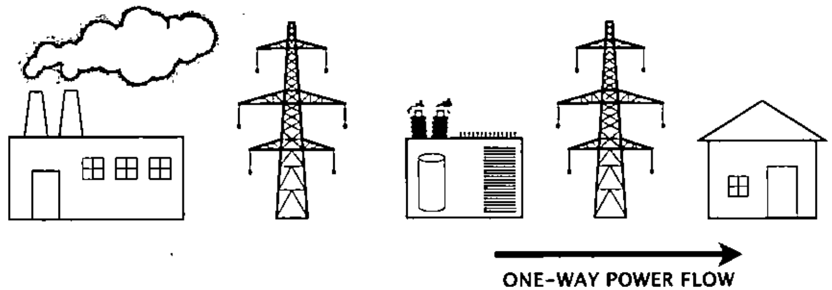
- Demand response
- Electric vehicles
- Thermal storage
- Battery storage

Distributed intelligence

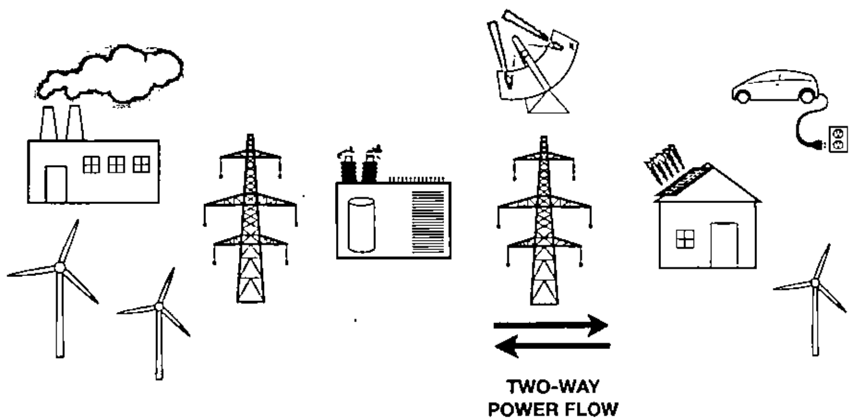
Technologies that combine sensory, communication, and control functions to support the electricity system, and magnify the value of DER system integration. Examples include:

- Smart inverters
- Home-area networks
- Microgrids

CURRENT SYSTEM/VALUE CHAIN:



FUTURE SYSTEM/VALUE CONSTELLATION:



WHAT MAKES DERs UNIQUE:

Siting

Smaller, more modular energy resources can be installed by disparate actors outside of the purview of centrally coordinated resource planning.

Operations

Energy resources on the distribution network operate outside of centrally controlled dispatching mechanisms that control the real-time balance of generation and demand.

Ownership

DERs can be financed, installed or owned by the customer or a third party, broadening the typical planning capability and resource integration approach.

STRUCTURAL MISALIGNMENTS

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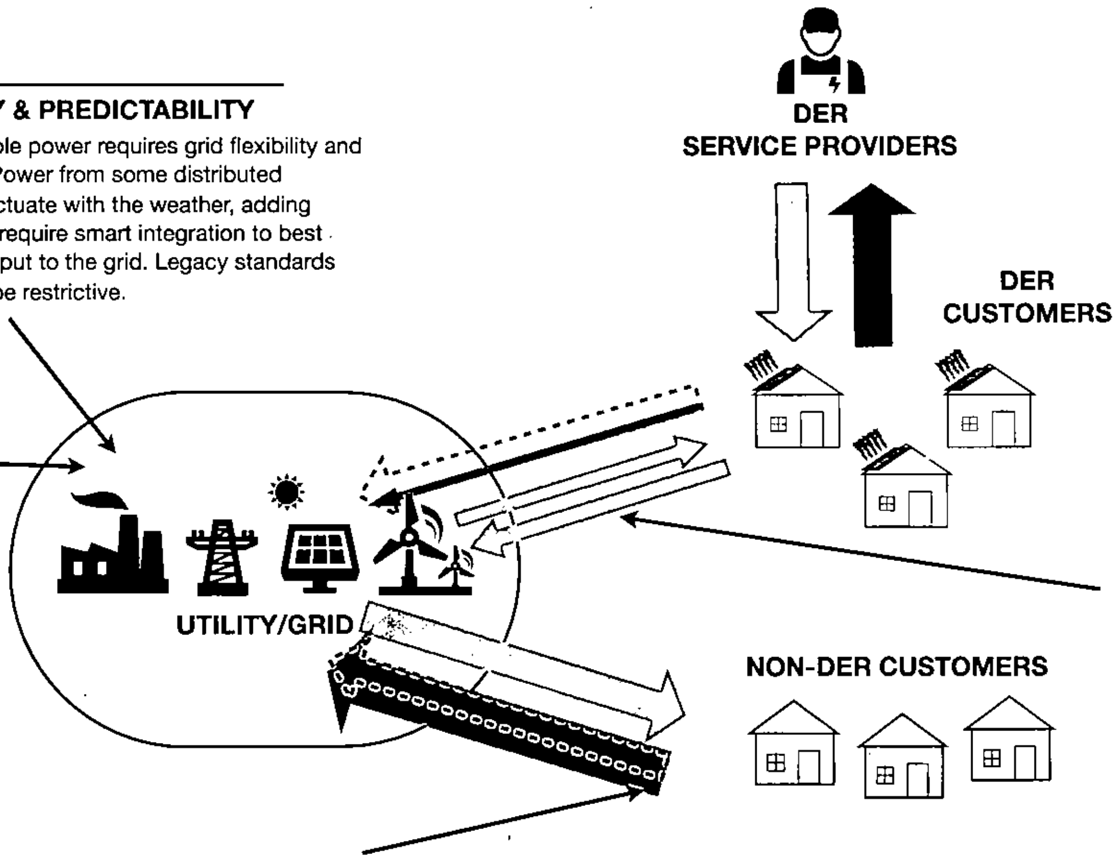
TODAY, OPERATIONAL AND PRICING MECHANISMS DESIGNED FOR AN HISTORICALLY CENTRALIZED ELECTRICITY SYSTEM ARE NOT WELL-ADAPTED TO THE INTEGRATION OF DERS, CAUSING FRICTION AND INEFFICIENCY

FLEXIBILITY & PREDICTABILITY

Providing reliable power requires grid flexibility and predictability. Power from some distributed renewables fluctuate with the weather, adding variability, and require smart integration to best shape their output to the grid. Legacy standards and rules can be restrictive.



LOCATION & TIME

Limited feedback loop to customers that the costs or benefit of any electricity resource, especially DERs, vary by location and time.

BENEFIT AND COST RECOGNITION AND ALLOCATION

Mechanisms are not in place to transparently recognize or compensate service (be it monetized grid services like energy, capacity or balancing supply and demand, or less consistently monetized values, such as carbon emissions savings) provided by the utility or the customer. To the utility, revenue from DER customers may not match the cost to serve those customers. To the customer, bill savings or credit may not match the value provided.

SOCIAL PRIORITIES

Society values the environmental and social benefits that DERs could provide, but those benefits are often externalized and unmonetized.

SOCIAL EQUITY

If costs are incurred by DER customers that are not paid for, those costs would be allocated to the rest of customers. Conversely, DER customers also provide benefits to other customers and to society.

$$ service

Adapted from RMI, Net Energy Metering, Zero Net Energy And The Distributed Energy Resource Future: Adapting Electric Utility Business Models For The 21st Century

STRUCTURAL MISALIGNMENTS IN PRACTICE

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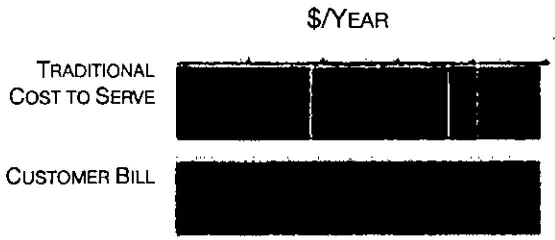
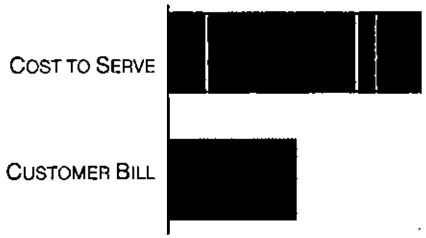
THESE STRUCTURAL MISALIGNMENTS ARE LEADING TO IMPORTANT QUESTIONS, DEBATE, AND CONFLICT

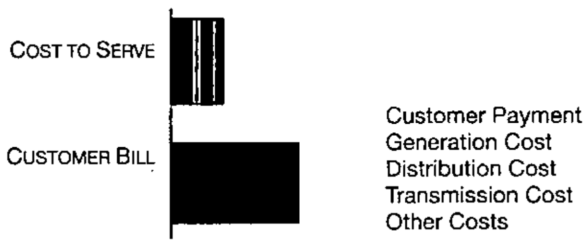
VALUE UNCERTAINTY...



WHAT IF A DPV CUSTOMER DOES NOT PAY FOR THE FULL COST TO SERVE THEIR DEMAND?



WHAT IF A DPV CUSTOMER IS NOT FULLY COMPENSATED FOR THE SERVICE THEY PROVIDE?



...DRIVES HEADLINES...

...RAISING KEY QUESTIONS

- What benefits can customers provide? Is the ability of customers to provide benefits contingent on anything?
- What costs are incurred to support DPV customer needs?
- What are the best practice methodologies to assess benefits and costs?
- How should externalized and unmonetized values, such as environmental and social benefits, be recognized?
- How can benefits and costs be more effectively allocated and priced?

SETTING THE STAGE

02

defining value
categories of value
stakeholder implications

SETTING THE STAGE

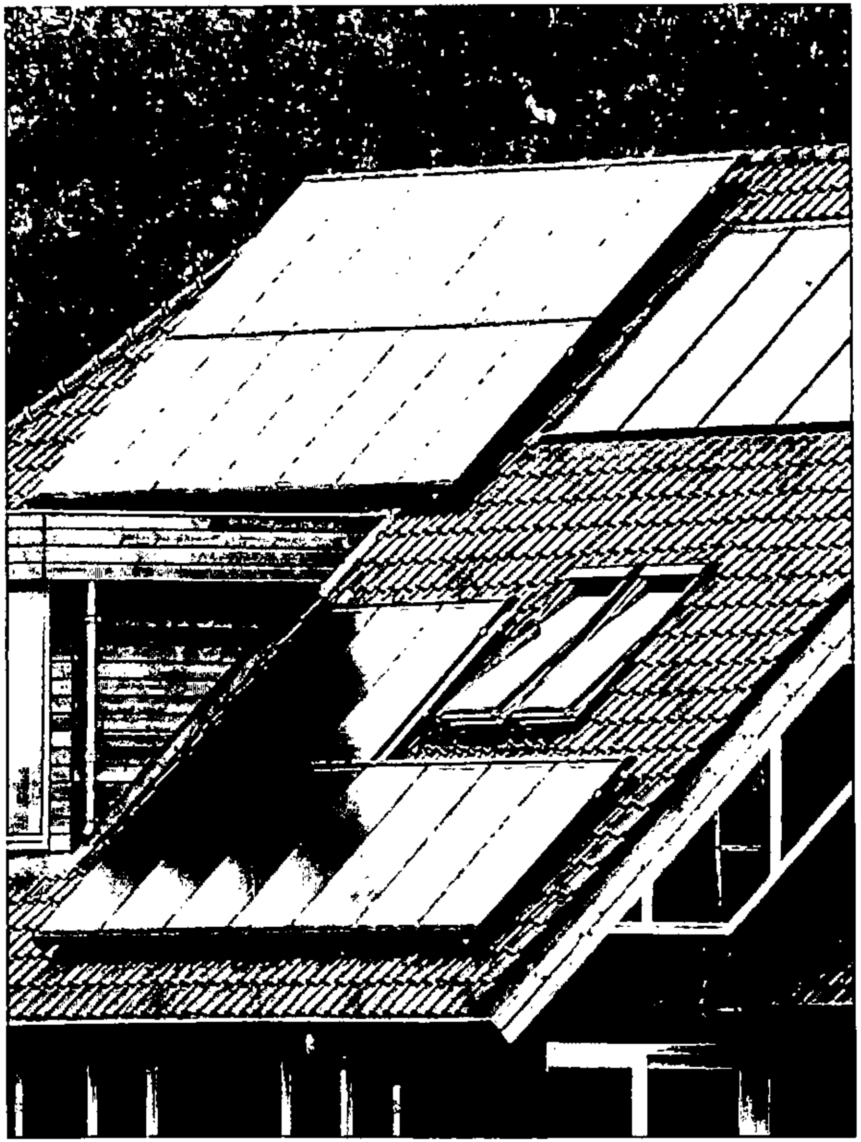
- When considering the total value of DPV or any electricity resource, it is critical to consider the types of value, the stakeholder perspective and the flow of benefits and costs–that is, who incurs the costs and who receives the benefits (or avoids the costs).

- For the purposes of this report, value is defined as net value, i.e. benefits minus costs. Depending upon the size of the benefit and the size of the cost, value can be positive or negative.

- A variety of categories of benefits or costs of DPV have been considered or acknowledged in evaluating the value of DPV. Broadly, these categories are: energy, system losses, capacity (generation, transmission and distribution), grid support services, financial risk, security risk, environmental and social.

- These categories of costs and benefits differ significantly by the degree to which they are readily quantifiable or there is a generally accepted methodology for doing so. For example, there is general agreement on overall approach to estimating energy value and some philosophical agreement on capacity value, although there remain key differences in capacity methodology. There is significantly less agreement on overall approach to estimating grid support services and currently unmonetized values including financial and security risk, environment, and social value.

- Equally important, the qualification of whether a factor is a benefit or cost also differs depending upon the perspective of the stakeholder. Similar to the basic framing of testing cost effectiveness for energy efficiency, the primary stakeholders in calculating the value of DPV are: the participant (the solar customer); the utility; other customers (also referred to as ratepayers); and society (taxpayers are a subset of society).



BENEFIT & COST CATEGORIES

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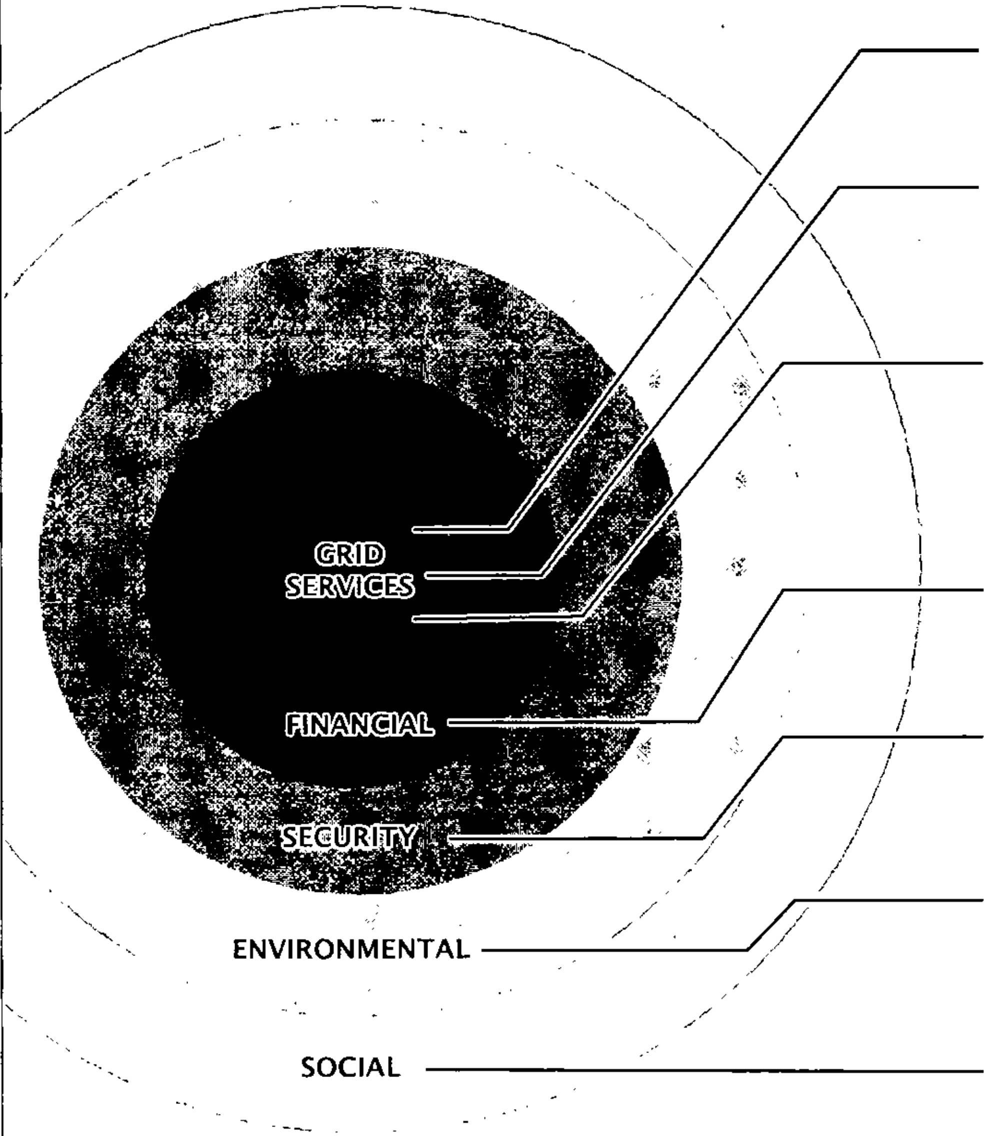
For the purposes of this report, **value is defined as net value, i.e. benefits minus costs.** Depending upon the size of the benefit and the size of the cost, value can be positive or negative. A variety of categories of benefits or costs of DPV have been considered or acknowledged in evaluating the value of DPV. Broadly, these categories are:



ENERGY
- energy
- system losses

CAPACITY
- generation capacity
- transmission & distribution capacity
- DPV installed capacity

GRID SUPPORT SERVICES
- reactive supply & voltage control
- regulation & frequency response
- energy & generator imbalance
- synchronized & supplemental operating reserves
- scheduling, forecasting, and system control & dispatch

FINANCIAL RISK
- fuel price hedge
- market price response

SECURITY RISK
- reliability & resilience

ENVIRONMENTAL
- carbon emissions (CO_2)
- criteria air pollutants (SO_2, NO_x, PM)
- water
- land

SOCIAL
- economic development (jobs and tax revenues)

BENEFIT & COST CATEGORIES DEFINED

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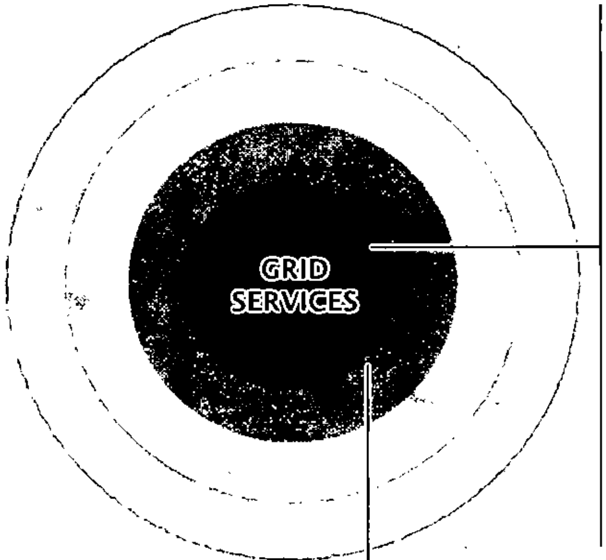


ENERGY

Energy value of DPV is positive when the solar energy generated displaces the need to produce energy from another resource at a net savings. There are two primary components:

- **Avoided Energy** - The cost and amount of energy that would have otherwise been generated to meet customer needs, largely driven by the variable costs of the marginal resource that is displaced. In addition to the coincidence of solar generation with demand and generation, key drivers of avoided energy cost include (1) fuel price forecast, (2) variable operation & maintenance costs, and (3) heat rate.

- **System Losses** - The compounded value of the additional energy generated by central plants that would otherwise be lost due to inherent inefficiencies (electrical resistance) in delivering energy to the customer via the transmission and distribution system. Since DPV generates energy at or near the customer, those losses are avoided. Losses act as a magnifier of value for capacity and environmental benefits, since avoided energy losses result in lower required capacity and lower emissions.

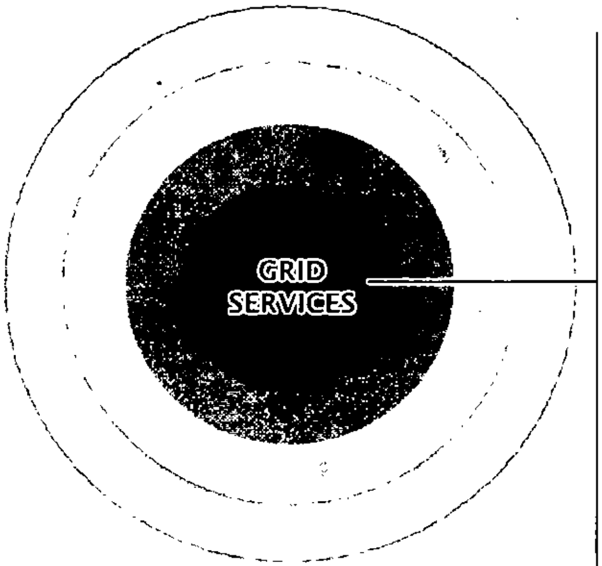
CAPACITY

Capacity value of DPV is positive when the addition of DPV defers or avoids more investment in generation, transmission, and distribution assets than it incurs. There are two primary components:

- **Generation Capacity** - The cost of the amount of central generation capacity that can be deferred or avoided due to the addition of DPV. Key drivers of value include (1) DPV's effective capacity and (2) system capacity needs.

- **Transmission & Distribution Capacity** - The value of the net change in T&D infrastructure investment due to DPV. Benefits occur when DPV is able to meet rising demand locally, relieving capacity constraints upstream and deferring or avoiding T&D upgrades. Costs occur when additional T&D investment is needed to support the addition of DPV.

BENEFIT & COST CATEGORIES DEFINED



GRID SUPPORT SERVICES

Grid support value of DPV is positive when the net amount and cost of grid support services required to balance supply and demand is less than would otherwise have been required. Grid support services, which encompass more narrowly defined ancillary services (AS), are those services required to enable the reliable operation of interconnected electric grid systems. Grid support services include:

- **Reactive Supply and Voltage Control**— Generation facilities used to supply reactive power and voltage control.

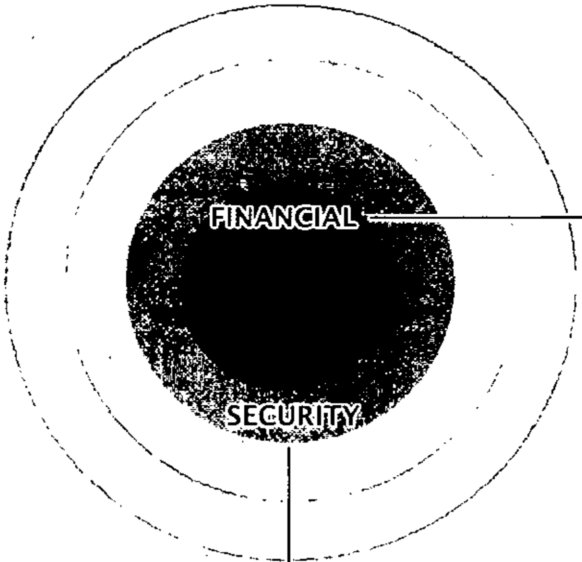
- **Frequency Regulation**—Control equipment and extra generating capacity necessary to (1) maintain frequency by following the moment-to-moment variations in control area load (supplying power to meet any difference in actual and scheduled generation), and (2) to respond automatically to frequency deviations in their networks. While the services provided by regulation service and frequency response service are different, they are complementary services made available using the same equipment and are offered as part of one service.

- **Energy Imbalance**—This service supplies any hourly net mismatch between scheduled energy supply and the actual load served.

- **Operating Reserves**—Spinning reserve is provided by generating units that are on-line and loaded at less than maximum output, and should be located near the load (typically in the same control area). They are available to serve load immediately in an unexpected contingency. Supplemental reserve is generating capacity used to respond to contingency situations that is not available instantaneously, but rather within a short period, and should be located near the load (typically in the same control area).

- **Scheduling/Forecasting**—Interchange schedule confirmation and implementation with other control areas, and actions to ensure operational security during the transaction.

BENEFIT & COST CATEGORIES DEFINED



FINANCIAL RISK

Financial value of DPV is positive when financial risk or overall market price is reduced due to the addition of DPV. Two components considered in the studies reviewed are:

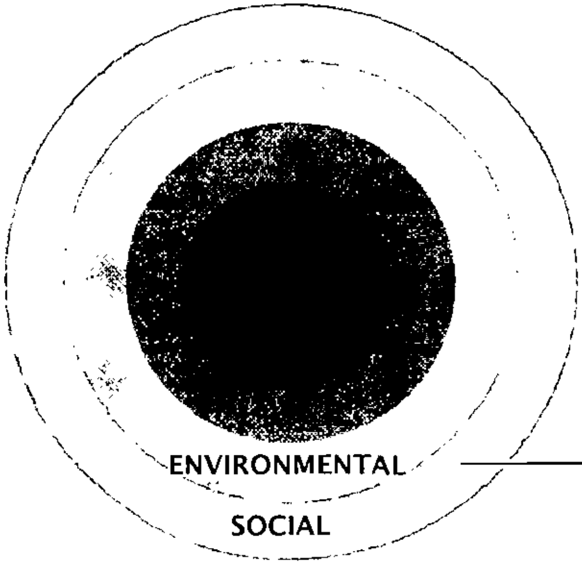
- **Fuel Price Hedge** - The cost that a utility would otherwise incur to guarantee that a portion of electricity supply costs are fixed.

- **Market Price Response** - The price impact as a result of DPV's reducing demand for centrally-supplied electricity and the fuel that powers those generators, thereby lowering electricity prices and potentially commodity prices.

SECURITY RISK

Security value of DPV is positive when grid reliability and resiliency are increased by (1) reducing outages by reducing congestion along the T&D network, (2) reducing large-scale outages by increasing the diversity of the electricity system's generation portfolio with smaller generators that are geographically dispersed, and (3) providing back-up power sources available during outages through the combination of PV, control technologies, inverters and storage.

BENEFIT & COST CATEGORIES DEFINED



ENVIRONMENTAL

Environmental value of DPV is positive when DPV results in the reduction of environmental or health impacts that would otherwise have been created. Key drivers include primarily the environmental impacts of the marginal resource being displaced. There are four components of environmental value:

- **Carbon** - The value from reducing carbon emissions is driven by the emission intensity of displaced marginal resource and the price of emissions.

- **Criteria Air Pollutants** - The value from reducing criteria air pollutant emissions—NO_x, SO_2, and particulate matter—is driven by the cost of abatement technologies, the market value of pollutant reductions, and/or the cost of human health damages.

- **Water** - The value from reducing water use is driven by the differing water consumption patterns associated with different generation technologies, and is sometimes measured by the price paid for water in competing sectors.

- **Land** - The value associated with land is driven by the difference in the land footprint required for energy generation and any change in property value driven by the addition of DPV.

- **Avoided Renewable Portfolio Standard costs (RPS)** - The value derived from meeting electricity demand through DPV, which reduces total demand that would otherwise have to be met and the associated renewable energy that would have to be procured as mandated by an RPS.

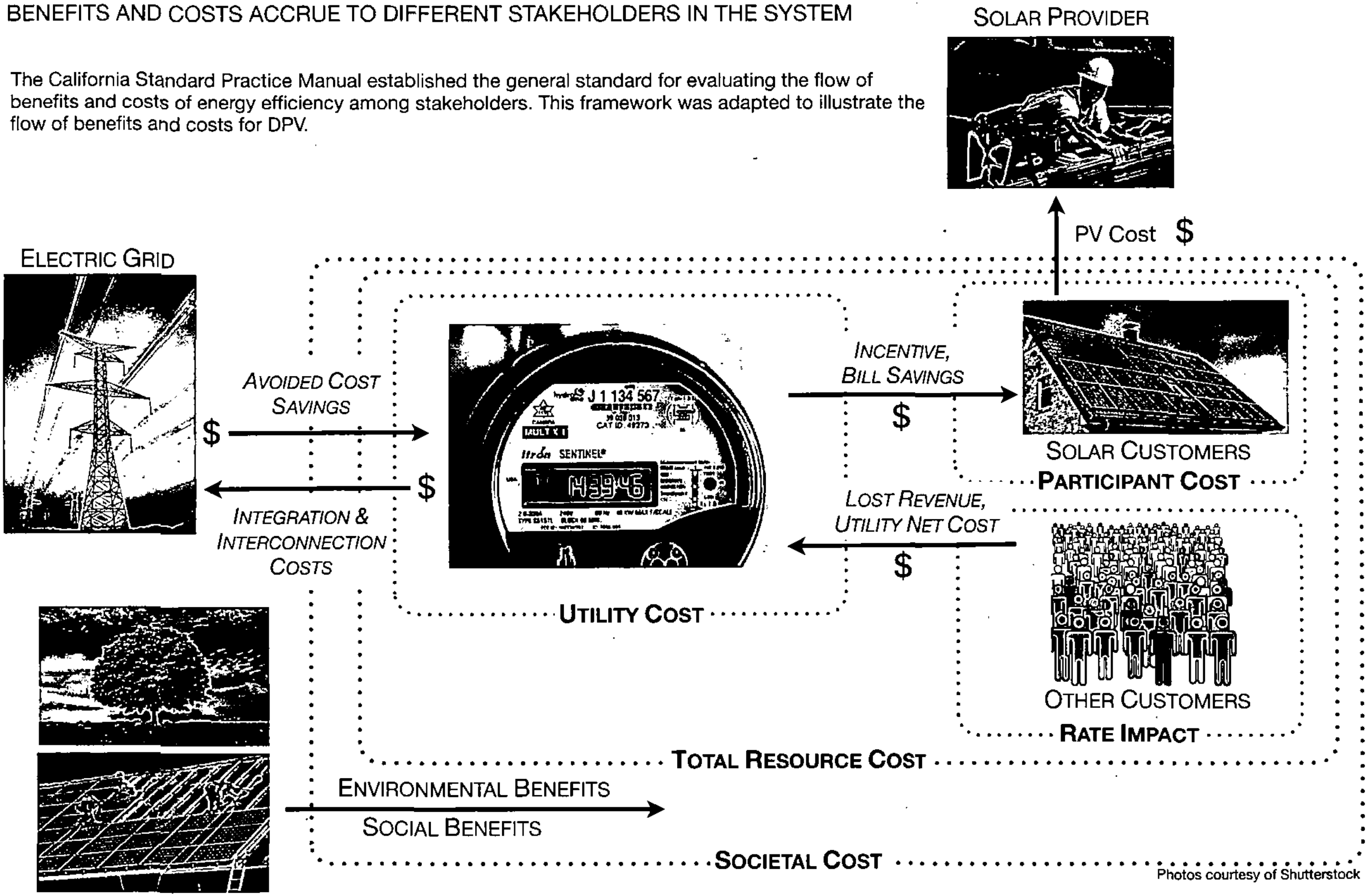
SOCIAL

The studies reviewed in this report defined social value in economic terms. The social value of DPV was positive when DPV resulted in a net increase in jobs and local economic development. Key drivers include the number of jobs created or displaced, as measured by a job multiplier, as well as the value of each job, as measured by average salary and/or tax revenue.

FLOW OF BENEFITS AND COSTS

BENEFITS AND COSTS ACCRUE TO DIFFERENT STAKEHOLDERS IN THE SYSTEM

The California Standard Practice Manual established the general standard for evaluating the flow of benefits and costs of energy efficiency among stakeholders. This framework was adapted to illustrate the flow of benefits and costs for DPV.



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STAKEHOLDER PERSPECTIVES

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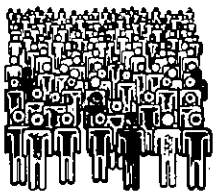
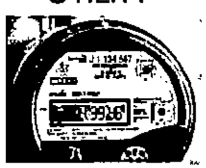
stakeholder perspective		factors affecting value
PV CUSTOMER 	"I want to have a predictable return on my investment, and I want to be compensated for benefits I provide."	Benefits include the reduction in the customer's utility bill, any incentive paid by the utility or other third parties, and any federal, state, or local tax credit received. Costs include cost of the equipment and materials purchased (inc. tax & installation), ongoing O&M, removal costs, and the customer's time in arranging the installation.
OTHER CUSTOMERS 	"I want reliable power at lowest cost."	Benefits include reduction in transmission, distribution, and generation, capacity costs; energy costs and grid support services. Costs include administrative costs, rebates/incentives, and decreased utility revenue that is offset by increased rates.
UTILITY 	"I want to serve my customers reliably and safely at the lowest cost, provide shareholder value and meet regulatory requirements."	Benefits include reduction in transmission, distribution, and generation, capacity costs; energy costs and grid support services. Costs include administrative costs, rebates/incentives, decreased revenue, integration & interconnection costs.
SOCIETY 	"We want improved air/water quality as well as an improved economy."	The sum of the benefits and costs to all stakeholder, plus any additional societal and environmental benefits or costs that accrue to society at large rather than any individual stakeholder.

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ANALYSIS FINDINGS

03

- analysis overview
- summary of benefits and costs
- detail: categories of benefit and cost

ANALYSIS OVERVIEW

THIS ANALYSIS INCLUDES 16 STUDIES, REFLECTING DIVERSE DPV PENETRATION LEVELS

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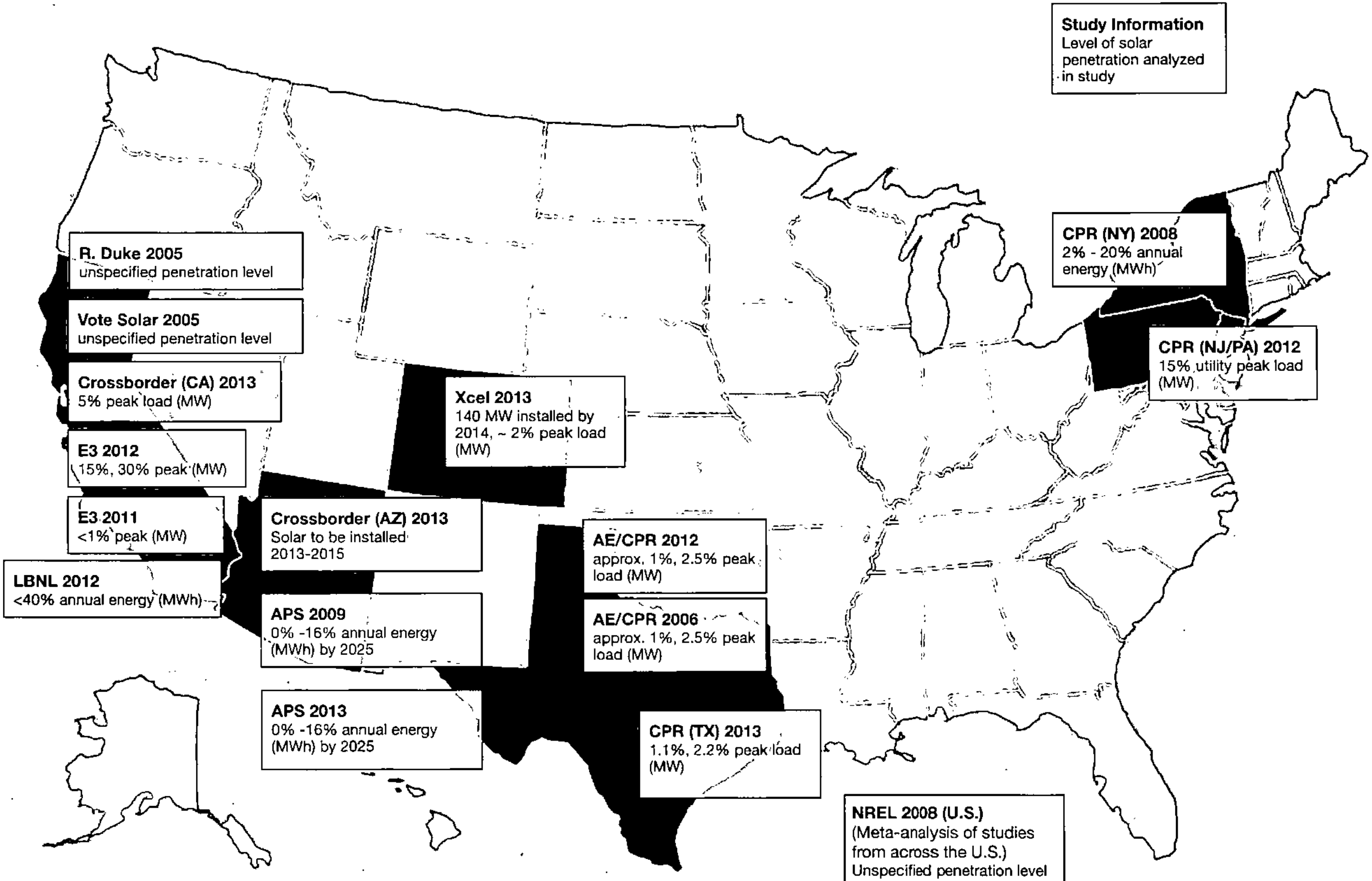

SUMMARY OF DPV BENEFITS AND COSTS

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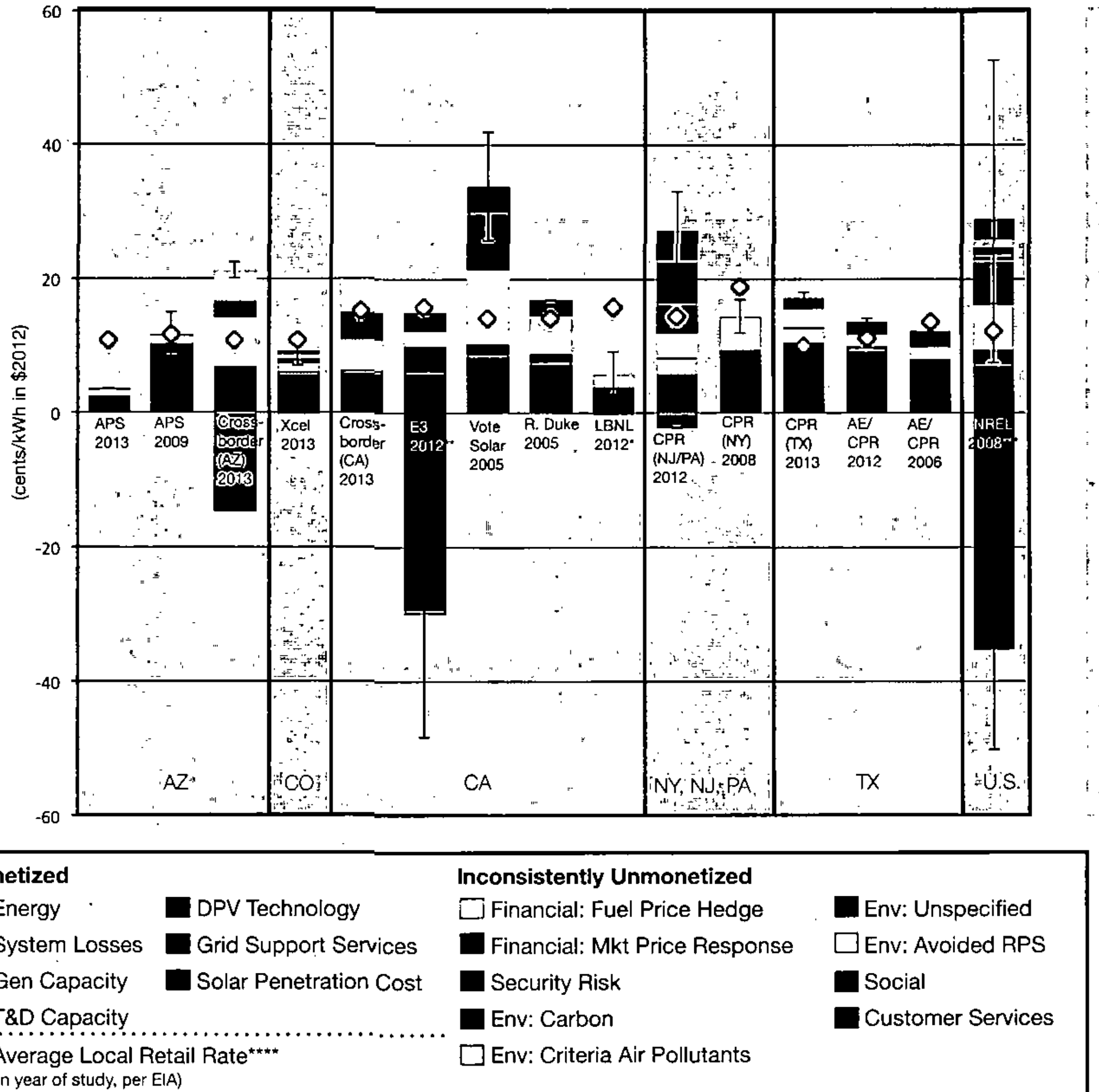
BENEFITS AND COSTS OF DISTRIBUTED PV BY STUDY



INSIGHTS

- No study comprehensively evaluated the benefits and costs of DPV, although many acknowledge additional sources of benefit or cost and many agree on the broad categories of benefit and cost.
- There is a significant range of estimated value across studies, driven primarily by differences in local context, input assumptions, and methodological approaches.
- Because of these differences, comparing results across studies can be informative, but should be done with the understanding that results must be normalized for context, assumptions, or methodology.
- While detailed methodological differences abound, there is some agreement on overall approach to estimating energy and capacity value. There is significantly less agreement on overall approach to estimating grid support services and currently unmonetized values including financial and security risk, environment, and social value.

* The LBNL study only gives the net value for ancillary services
** E3's DPV technology cost includes LCOE + interconnection cost
*** The NREL study is a meta-analysis, not a research study. Customer Services, defined as the value to customer of a green option, was only reflected in the NREL 2008 meta-analysis and not included elsewhere in this report.
****Average retail rate included for reference; it is not appropriate to compare the average retail rate to total benefits presented without also reflecting costs (i.e., net value) and any material differences within rate designs (i.e., not average).
Note: E3 2012 study not included in this chart because that study did not itemize results. See page 47.

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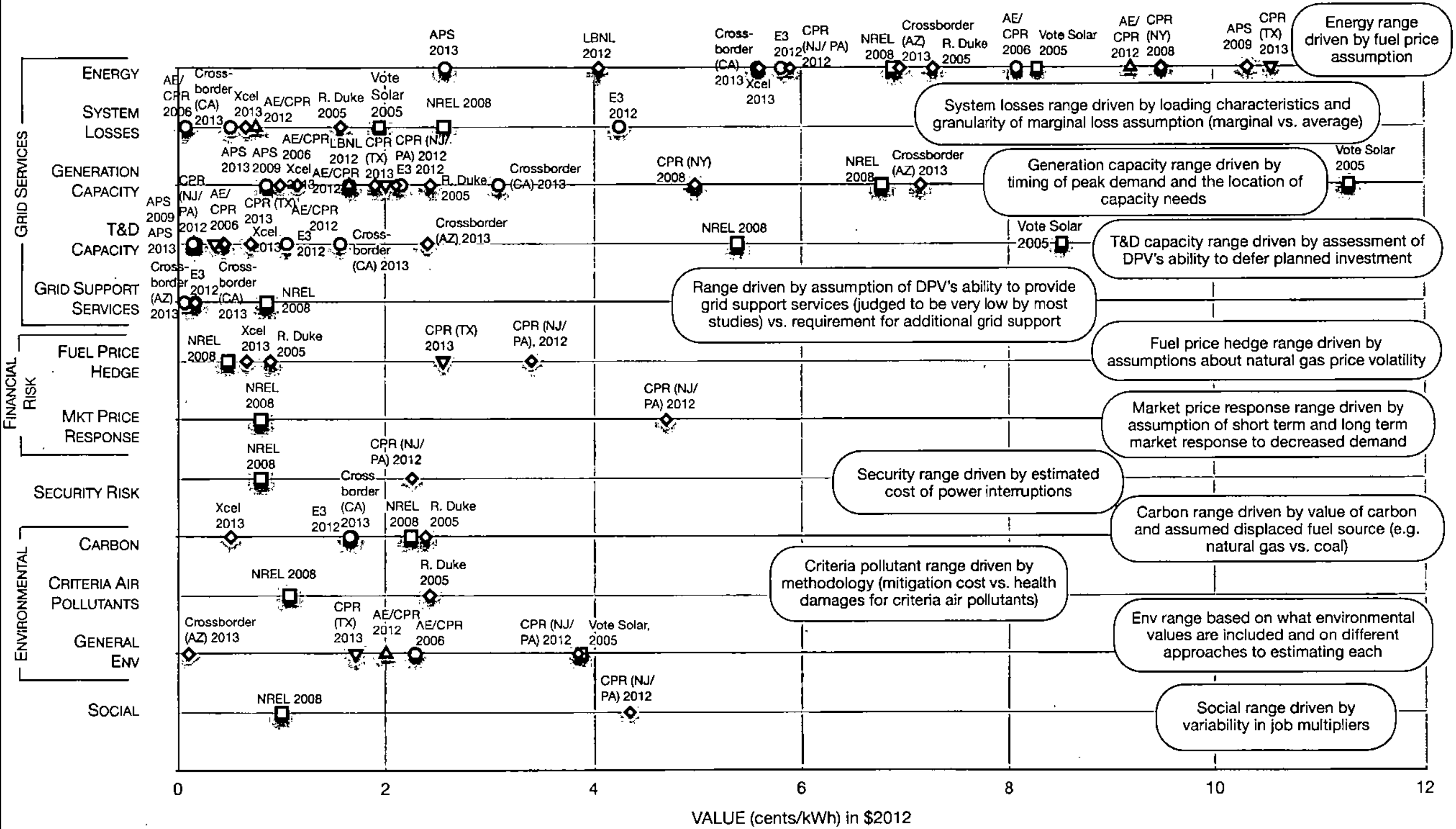
BENEFIT ESTIMATES

THE RANGE IN BENEFIT ESTIMATES ACROSS STUDIES IS DRIVEN BY VARIATION IN SYSTEM CONTEXT, INPUT ASSUMPTIONS, AND METHODOLOGIES

PUBLISHED AVERAGE BENEFIT ESTIMATES*



*For the full range of values observed see the individual methodology slides.

COST ESTIMATES

COSTS ASSOCIATED WITH INCREASED DPV DEPLOYMENT ARE NOT ADEQUATELY ASSESSED

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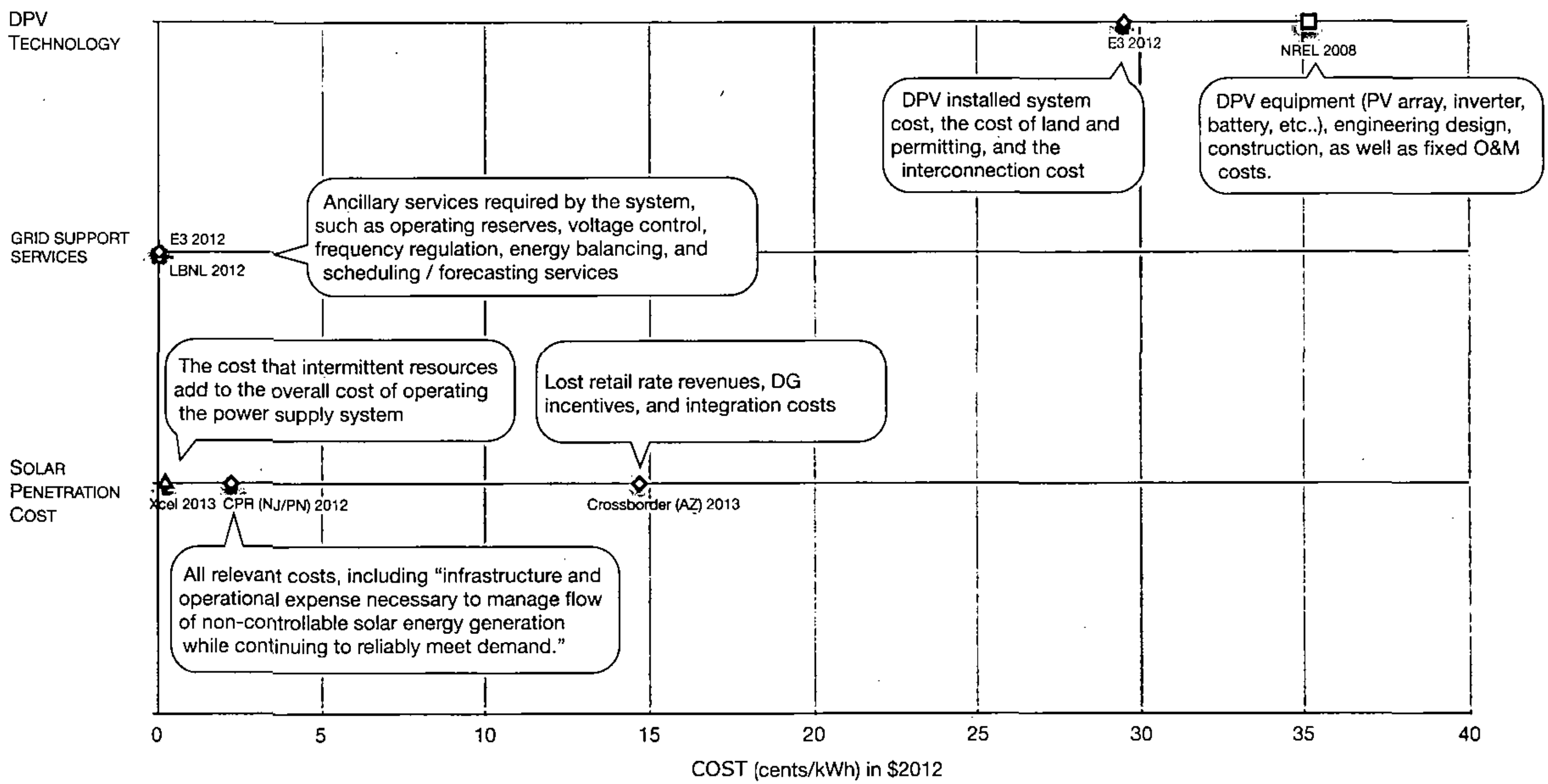
PUBLISHED AVERAGE COST VALUES FOR REVIEWED SOURCES



Other studies (for example E3 2011) include costs, but results are not presented individually in the studies and so not included in the chart above. Costs generally include costs of program rebates or incentives paid by the utility, program administration costs, lost revenue to the utility, stranded assets, and costs and inefficiencies associated with throttling down existing plants.

ENERGY

VALUE OVERVIEW

Energy value is created when DPV generates energy (kWh) that displaces the need to produce energy from another resource. There are two components of energy value: the amount of energy that would have been generated equal to the DPV generation, and the additional energy that would have been generated but lost in delivery due to inherent inefficiencies in the transmission and distribution system. This second category of losses is sometimes reflected separately as part of the system losses category.

APPROACH OVERVIEW

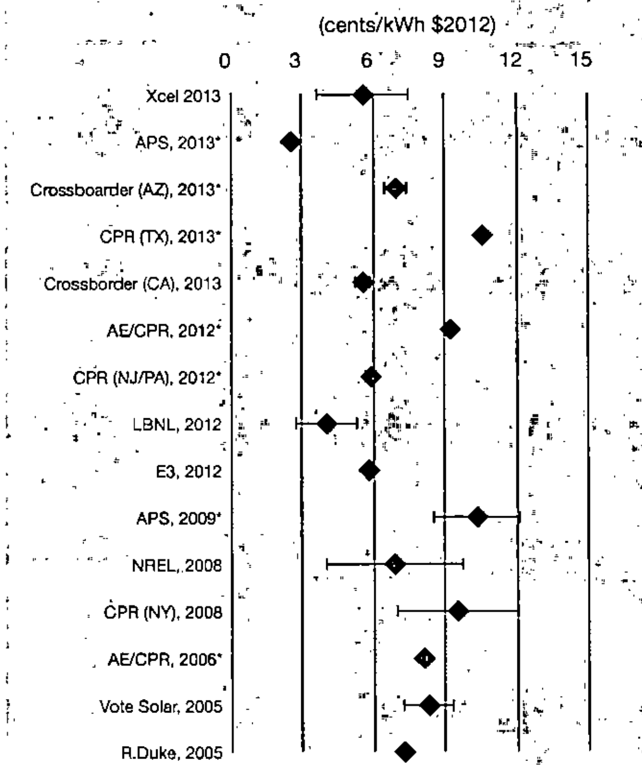
There is broad agreement on the general approach to calculating energy value, although numerous differences in methodological details. Energy is frequently the most significant source of benefit.

- Energy value is the avoided cost of the marginal resource, typically assumed to be natural gas.
- Key assumptions generally include fuel price forecast, operating & maintenance costs, and heat rate, and depending on the study, can include system losses and a carbon price.

WHY AND HOW VALUES DIFFER

- **System Context:**
  - **Market structure** - Some Independent System Operators (ISOs) and states value capacity and energy separately, whereas some ISOs only have energy markets without capacity markets. ISOs with only energy markets may reflect capacity value in the energy price.
  - **Marginal resource characterization** - Studies in regions with ISOs may calculate the marginal price based on wholesale market prices, rather than on the cost of the marginal power plant; different resources may be on the margin in different regions or with different solar penetrations.
- **Input Assumptions:**
  - **Fuel price forecast** - Since natural gas is usually on the margin, most studies focus on natural gas prices. Studies most often base natural gas prices on the New York Mercantile Exchange (NYMEX) forward market and then extrapolate to some future date (varied approaches to this extrapolation), but some take a different approach to forecasting, for example, based on Energy Information Administration projections.
  - **Power plant efficiency** - The efficiency of the marginal resource significantly impacts energy value; studies show a wide range of assumed natural gas plant heat rates.
  - **Variable operating & maintenance costs** - While there is some difference in values assumed by studies, variable O&M costs are generally low.
  - **Carbon price** - Some studies include an estimated carbon price in energy value, others account for it separately, and others do not include it at all.
- **Methodologies:**
  - **Study window** - Some studies (for example, APS 2013) calculate energy value in a sample year, whereas others (for example, Crossborder (AZ) 2013) calculate energy value as a levelized cost over 20 years.
  - **Marginal resource characterization** - Studies take one of three general approaches: (1) DPV displaces energy from a gas plant, generally a combined cycle, (2) DPV displaces energy from one type of plant (generally a combined cycle) off-peak and a different type of plant (generally a combustion turbine) on-peak, (3) DPV displaces the resource on the margin during every hour of the year, based on a dispatch analysis.

ENERGY BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES



* = value energy savings that result from avoided energy losses

Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.

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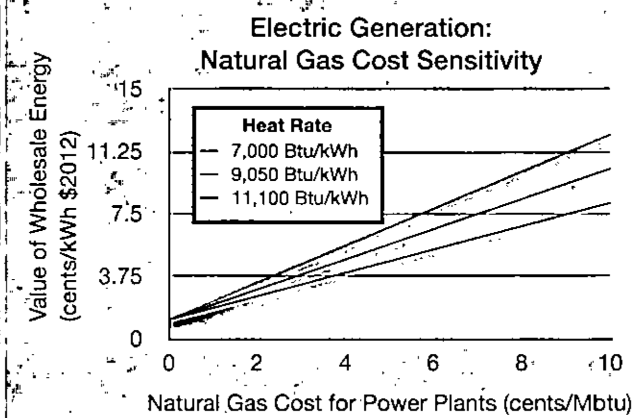
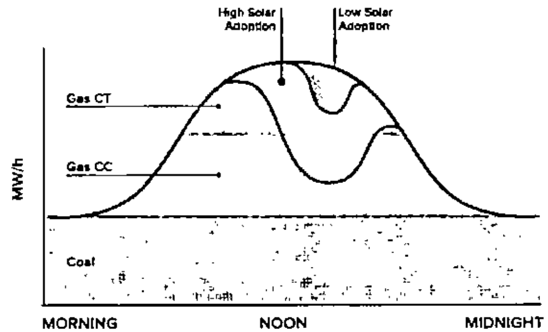
SENSITIVITIES TO KEY INPUT ASSUMPTIONS



INSIGHTS & IMPLICATIONS

- Accurately defining the marginal resource that DPV displaces requires an increasingly sophisticated approach as DPV penetration increases.



The resources that DPV displaces depends on the dispatch order of other resources, when the solar is generated, and how much is generated.

More accurate, more complex ↓

Marginal Resource Characterization	Pros	Cons
Single power plant assumed to be on the margin (typically gas CC)	Simple; often sufficiently accurate at low solar penetrations	Not necessarily accurate at higher penetrations or in all jurisdictions
Plant on the margin on-peak/plant on the margin off-peak	More accurately captures differences in energy value reflected in merit-order dispatch	Not necessarily accurate at higher penetrations or in all jurisdictions
Hourly dispatch or market assessment to determine marginal resource in every hour	Most accurate, especially with increasing penetration	More complex analysis required; solar shape and load shape must be from same years

- Taking a more granular approach to determining energy value also requires a more detailed characterization of DPV's generation profile. It's also critical to use solar and load profiles from the same year(s), to accurately reflect weather drivers and therefore generation and demand correlation.

- In cases where DPV is displacing natural gas, the NYMEX natural gas forward market is a reasonable basis for a natural gas price forecast, adjusted appropriately for delivery to the region in question. It is not apparent from studies reviewed what the most effective method is for escalating prices beyond the year in which the NYMEX market ends.

LOOKING FORWARD

As renewable and distributed resource (not just DPV) penetration increases, those resources will start to impact the underlying load shape differently, requiring more granular analysis to determine energy value.

SYSTEM LOSSES

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VALUE OVERVIEW

System losses are a derivation of energy losses, the value of the additional energy generated by central plants that is lost due to inherent inefficiencies (electrical resistance) in delivering energy to the customer via the transmission and distribution system. Since DPV generates energy at or near the customer, that additional energy is not lost. Energy losses act as a magnifier of value for capacity and environmental benefits, since avoided energy losses result in lower required capacity and lower emissions.

APPROACH OVERVIEW

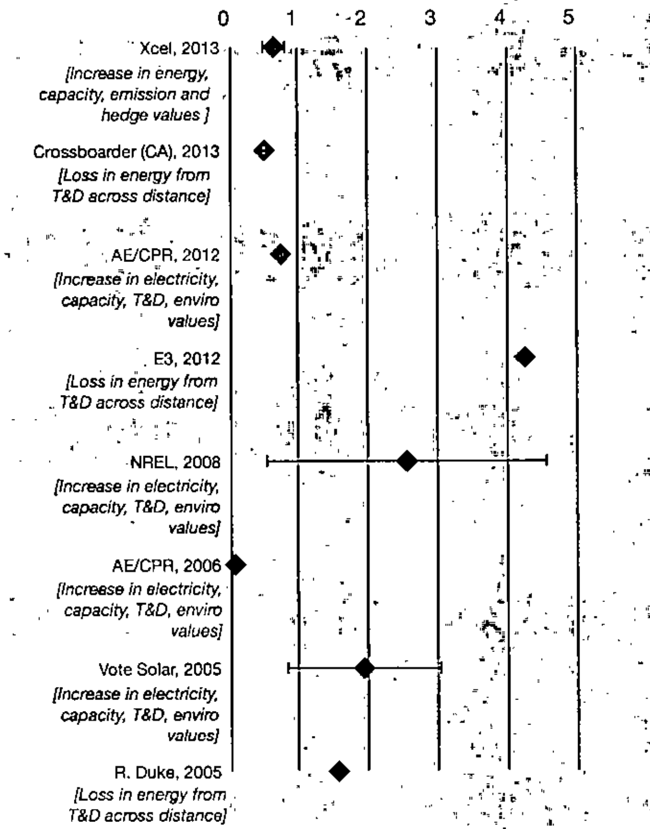
Losses are generally recognized as a value, although there is significant variation around what type of losses are included and how they are assessed. Losses usually represent a small but not insignificant source of value, although some studies report comparatively high values.

- Energy lost in delivery magnifies the value of other benefits, including capacity and environment.
- Calculate loss factor(s) (amount of loss per unit of energy delivered) based on modeled or observed data.

WHY AND HOW VALUES DIFFER

- **System Context:**
  - **Congestion** - Because energy losses are proportional to the inverse of current squared, the higher the utilization of the transmission & distribution system, the greater the energy losses.
  - **Solar characteristics** - The timing, quantity, and geographic location of DPV, and therefore its coincidence with delivery system utilization, impacts losses.
- **Input Assumptions:**
  - **Losses** - Some studies estimate losses by applying loss factors based on actual observation, others develop theoretical loss factors based on system modeling. Further, some utility systems have higher losses than others.
- **Methodologies:**
  - **Types of losses recognized** - Most studies recognize energy losses, some recognize capacity losses, and a few recognize environmental losses.
  - **Adder vs. stand-alone value** - There is no common approach to whether losses are represented as stand-alone values (for example, NREL 2008 and E3 2012) or as adders to energy, capacity, and environmental value (for example, Crossborder (AZ) 2013 and APS 2013), complicating comparison across studies.
  - **Temporal & geographic characterization** - Some studies apply an average loss factor to all energy generated by DPV, others apply peak/off-peak factors, and others conduct hourly analysis. Some studies also reflect geographically-varying losses.

SYSTEM LOSSES BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES (cents/kWh $2012)

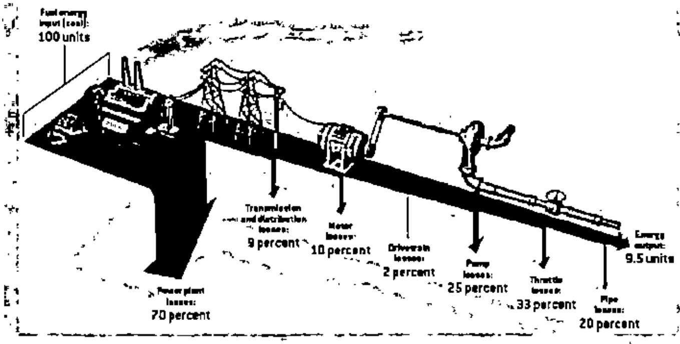


Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.

SYSTEM LOSSES (CONT'D)

WHAT ARE SYSTEM LOSSES?

Some energy generated at a power plant is lost as it travels through the transmission and distribution system to the customer. As shown in the graphic below, more than 90% of primary energy input into a power plant is lost before it reaches the end use, or stated in reverse, for every one unit of energy saved or generated close to where it is needed, 10 units of primary energy are saved.



For the purposes of this discussion document, relevant losses are those driven by inherent inefficiencies (electrical resistance) in the transmission and distribution system, not those in the power plant or customer equipment. Energy losses are proportional to the square of current, and associated capacity benefit is proportional to the square of reduced load.

INSIGHTS & IMPLICATIONS

- All relevant system losses—energy, capacity, and environment—should be assessed.
- Because losses are driven by the square of current, losses are significantly higher during peak periods. Therefore, when calculating losses, it's critical to reflect marginal losses, not just average losses.
- Whether or not losses are ultimately represented as an adder to an underlying value or as a stand-alone value, they are generally calculated separately. Studies should distinguish these values from the underlying value for transparency and to drive consistency of methodology.

LOOKING FORWARD

Losses will change over time as the loading on transmission and distribution lines changes due to a combination of changing customer demand and DPV generation.

GENERATION CAPACITY

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VALUE OVERVIEW

Generation capacity value is the amount of central generation capacity that can be deferred or avoided due to the installation of DPV. Key drivers of value include (1) DPV's effective capacity and (2) system capacity needs.

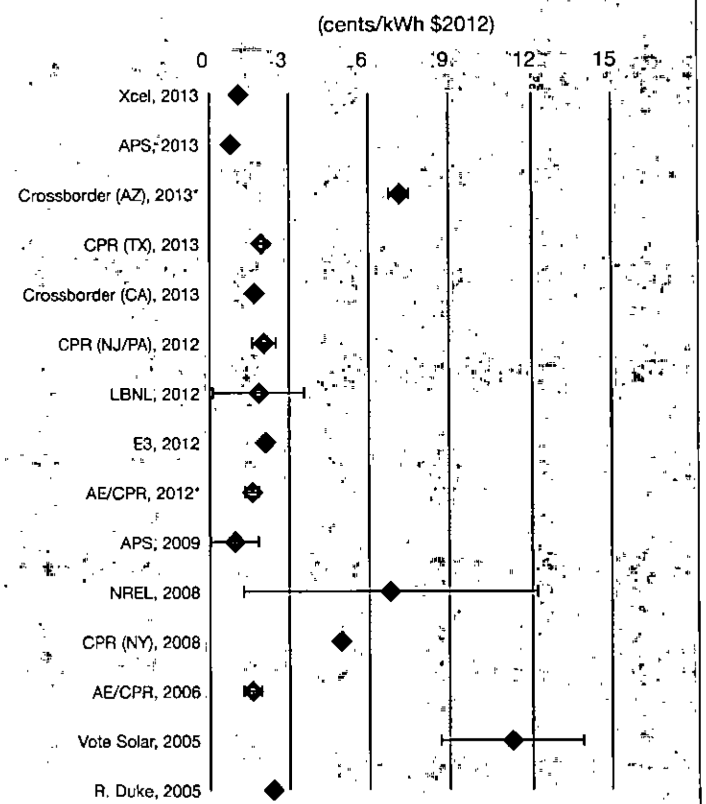
APPROACH OVERVIEW

Generation capacity value is the avoided cost of the marginal capacity resource, most frequently assumed to be a gas combustion turbine, and based on a calculation of DPV effective capacity, most commonly based on effective load carrying capability (ELCC).

WHY AND HOW VALUES DIFFER

- **System Context:**
  - **Load growth/generation capacity investment plan** - The ability to avoid or defer generation capacity depends on underlying load growth and how much additional capacity will be needed, at what time.
  - **Solar characteristics** - The timing, quantity, and geographic location of DPV, and therefore its coincidence with system peak, impacts DPV's effective capacity.
  - **Market structure** - Some ISOs and states value capacity and energy separately, whereas some ISOs only have energy markets but no capacity markets. ISOs with only energy markets may reflect capacity value as part of the energy price. For California, E3 2012 calculates capacity value based on "net capacity cost"—the annual fixed cost of the marginal unit minus the gross margins captured in the energy and ancillary service market.
- **Input Assumptions:**
  - **Marginal resource** - Most studies assume that a gas combustion turbine, or occasionally a gas combined cycle, is the generation capacity resource that could be deferred. What this resource is and its associated capital and fixed O&M costs are a primary determinant of capacity value.
- **Methodologies:**
  - **Formulation of DPV effective capacity** - There is broad agreement that DPV's effective capacity is most accurately determined using an ELCC approach, which measures the amount of additional load that can be met with the same level of reliability after adding DPV. There is some variation across studies in ELCC results, likely driven by a combination of underlying solar resource profile and ELCC calculation methodology. The approach to effective capacity is sometimes different when considering T&D capacity.
  - **Minimum DPV required to defer capacity** - Some studies (for example, Crossborder (AZ) 2013) credit every unit of effective DPV capacity with capacity value, whereas others (for example, APS 2009) require a certain minimum amount of solar be installed to defer an actual planned resource before capacity value is credited.
  - **Inclusion of losses** - Some studies include capacity losses as an adder to capacity value rather than as a stand-alone benefit.

GENERATION CAPACITY BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES



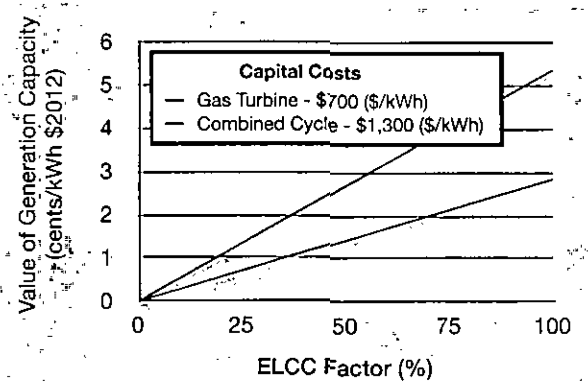
* = value includes generation capacity savings that result from avoided energy losses

Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.

GENERATION CAPACITY (CONT'D)

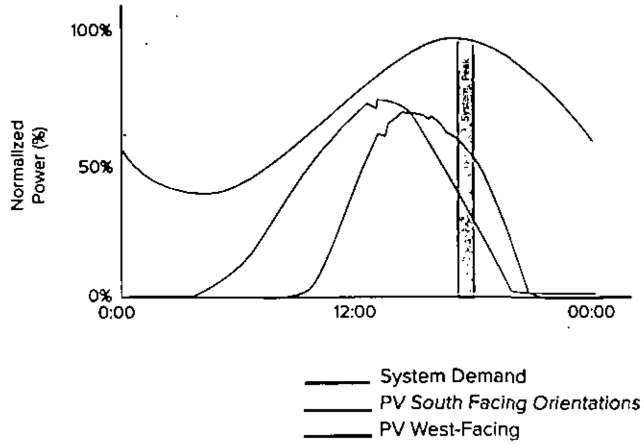
SENSITIVITIES TO KEY INPUT ASSUMPTIONS

Sensitivity of Generation Capacity Value to the ELCC Factor



INSIGHTS & IMPLICATIONS

- Generation capacity value is highly dependent on the correlation of DPV generation to load, so it's critical to accurately assess that correlation using an ELCC approach, as all studies reviewed do. However, varying results indicate possible different formulations of ELCC.



While effective load carrying capacity (ELCC) assesses DPV's contribution to reliability throughout the year, generation capacity value will generally be higher if DPV output is more coincident with peak.

- The value also depends on whether new capacity is needed on the system, and therefore whether DPV defers new capacity. It's important to assess what capacity would have been needed without any additional, expected, or planned DPV.

- Generation capacity value is likely to change significantly as more DPV, and more renewable and distributed resources of all kinds are added to the system. Some amount of DPV can displace the most costly resources in the capacity stack, but increasing amounts of DPV could begin to displace less costly resources. Similarly, the underlying load shape, and therefore even the concept of a peak could begin to shift.

LOOKING FORWARD

Generation capacity is one of the values most likely to change, most quickly, with increasing DPV penetration. Key reasons for this are (1) increasing DPV penetration could have the effect of pushing the peak to later in the day, when DPV generation is lower, and (2) increasing DPV penetration will displace expensive peaking resources, but once those resources are displaced, the cost of the next resource may be lower. Beyond DPV, it's important to note that a shift towards more renewables could change the underlying concept of a daily or seasonal peak.

TRANSMISSION & DISTRIBUTION CAPACITY

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VALUE OVERVIEW

The transmission and distribution (T&D) capacity value is a measure of the net change in T&D infrastructure as a result of the addition of DPV. Benefits occur when DPV is able to meet rising demand locally, relieving capacity constraints upstream and deferring or avoiding transmission or distribution upgrades. Costs are incurred when additional transmission or distribution investment are necessary to support the addition of DPV, which could occur when the amount of solar energy exceeds the demand in the local area and increases needed line capacity.

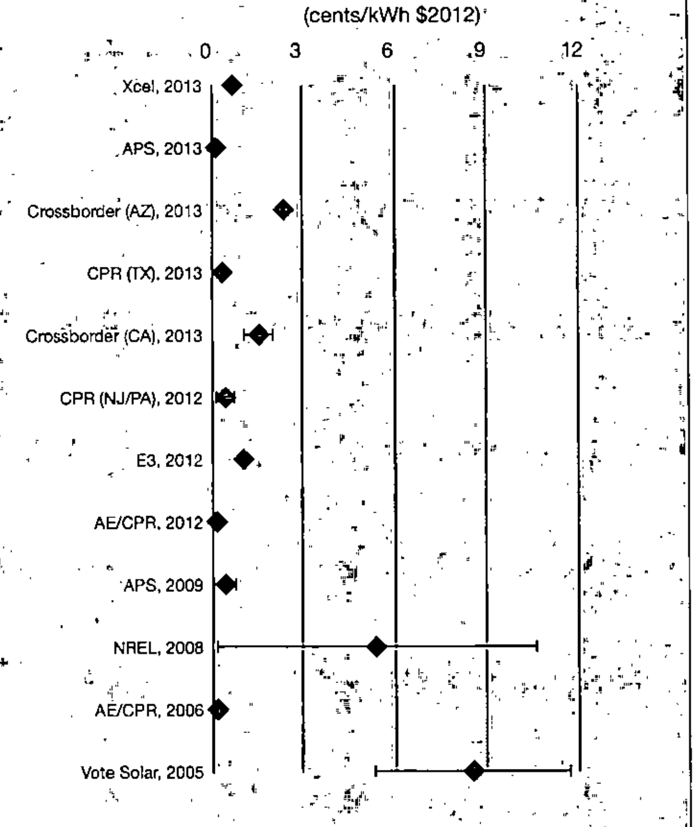
APPROACH OVERVIEW

The net value of deferring or avoiding T&D investments is driven by rate of load growth, DPV configuration and energy production, peak coincidence and effective capacity. Given the site specific nature of T&D, especially distribution, there can be significant range in the calculated value of DPV. Historically low penetrations of DPV has meant that studies have primarily focused on analyzing the ability of DPV to defer transmission or distribution upgrades and have not focused on potential costs, which would likely not arise until greater levels of penetration. Studies typically determine the T&D capacity value based on the capital costs of planned expansion projects in the region of interest. However, the granularity of analysis differs.

WHY AND HOW VALUES DIFFER

- **System Context:**
  - **Locational characteristics -** Transmission and distribution infrastructure projects are inherently site-specific and their age, service life, and use can vary significantly. Thus, the need, size and cost of upgrades, replacement or expansion correspondingly vary.
  - **Projected load growth/T&D capacity investment plan -** Expected rate of demand growth affects the need, scale and cost of T&D upgrades and the ability of DPV to defer or offset anticipated T&D expansions. The rate of growth of DPV would need to keep pace with the growth in demand, both by order of magnitude and speed.
  - **Solar characteristics** - The timing of energy production from DPV and its coincidence with system peaks (transmission) and local peaks (distribution) drive the ability of DPV to contribute as effective capacity that could defer or displace a transmission or distribution capacity upgrade.
  - **The length of time the investment is deferred** -The length of time that T&D can be deferred by the installation of DPV varies by the rate of load growth, the assumed effective capacity of the DPV, and DPV's correlation with peak. The cost of capital saved will increase with the length of deferment.
- **Input Assumptions:**
  - **T&D investment plan characteristics -** Depending upon data available and depth of analysis, studies vary by the level of granularity in which T&D investment plans were assessed–project by project or broader generalizations across service territories.
- **Methodologies:**
  - **Accrual of capacity value to DPV -** One of the most significant methodological differences is whether DPV has incremental T&D capacity value in the face of "lumpy" T&D investments (see implications and insights).
  - **Losses** - Some studies include the magnified benefit of deferred T&D capacity due to avoided losses within the calculation of T&D value, while others itemize line losses separately.

T&D CAPACITY BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES

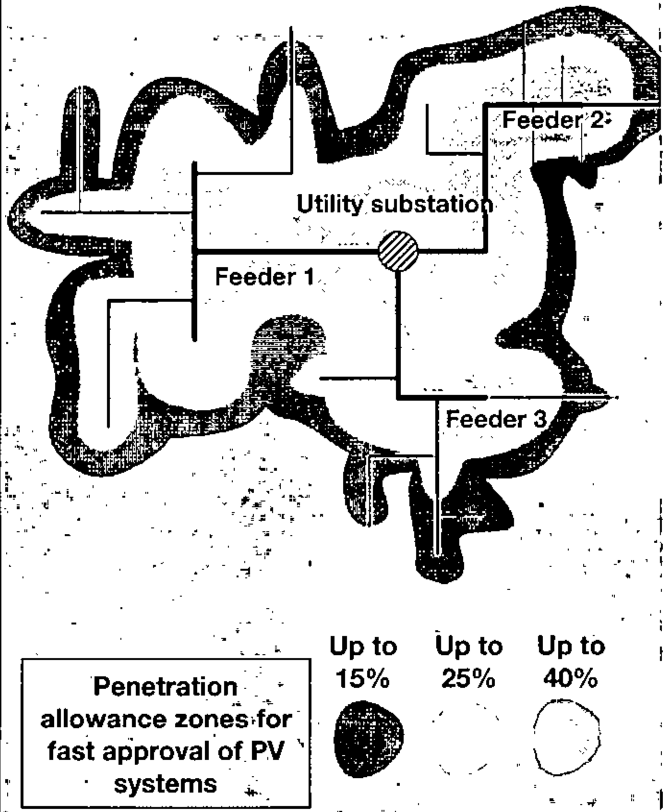


* = value includes T&D capacity savings that result from avoided energy losses

Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.

TRANSMISSION & DISTRIBUTION CAPACITY (CONT'D)

LOCATIONAL CONSIDERATIONS AT THE DISTRIBUTION LEVEL



Adapted from Coddington, M. et al, *Updating Interconnection Screens for PV System Integration*

INSIGHTS & IMPLICATIONS

- Strategically targeted DPV deployment can relieve T&D capacity constraints by providing power close to demand and potentially deferring capacity investments, but dispersed deployment has been found to provide less benefit. Thus, the ability to access DPV's T&D deferral value will require proactive distribution planning that incorporates distributed energy resources, such as DPV, into the evaluation.
- The values of T&D are often grouped together, but they are unique when considering the potential costs and benefits that result from DPV.
  - While the ability to defer or avoid transmission is still locational dependent, it is less so than distribution. Transmission aggregates disparate distribution areas and the effects of additional DPV at the distribution level typically require less granular data and analysis.
  - The distribution system requires more geographically specific data that reflects the site specific characteristics such as local hourly PV production and correlation with local load.
- There are significantly differing approaches on the ability of DPV to accrue T&D capacity deferment or avoidance value that require resolution:
  - How should DPV's capacity deferral value be estimated in the face of "lumpy" T&D investments? While APS 2009 and APS 2013 posit that a minimum amount of solar must be installed to defer capacity before credit is warranted, Crossborder (AZ) 2013 credits every unit of reliable capacity with capacity value.
  - What standard should be applied to estimate PV's ability to defer a specific distribution expansion project? While most studies use ELCC to determine effective capacity, APS 2009 and APS 2013 use the level at which there is a 90% confidence of that amount of generation.

LOOKING FORWARD

Any distributed resources, not just DPV, that can be installed near the end user to reduce use of, and congestion along, the T&D network could potentially provide T&D value. This includes technologies that allow energy to be used more efficiently or at different times, reducing the quantity of electricity traveling through the T&D network (especially during peak hours).

GRID SUPPORT SERVICES

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VALUE OVERVIEW

Grid support services, also commonly referred to as ancillary services (AS) in wholesale energy markets, are required to enable the reliable operation of interconnected electric grid systems, including operating reserves, reactive supply and voltage control; frequency regulation; energy imbalance; and scheduling.

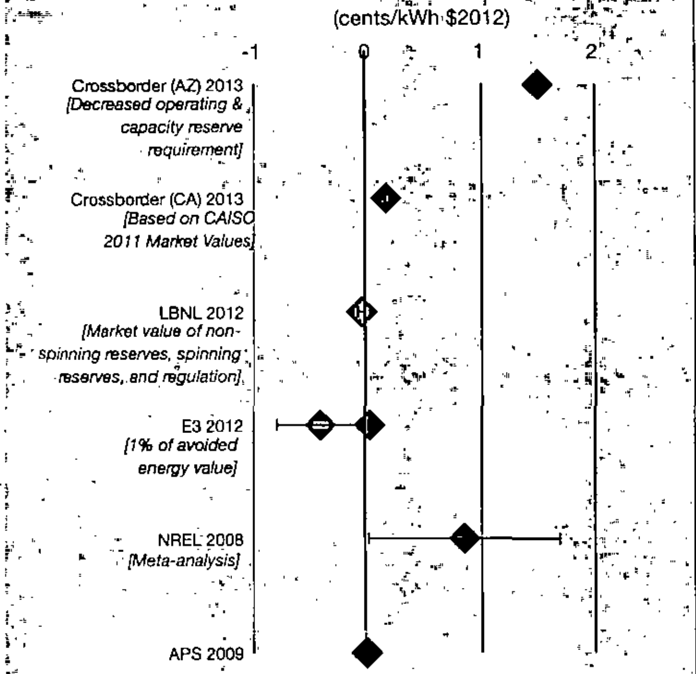
APPROACH OVERVIEW

There is significant variation across studies on the impact DPV will have on the addition or reduction in the need for grid support services and the associated cost or benefit. Most studies focus on the cost DPV could incur in requiring additional grid support services, while a minority evaluate the value DPV could provide by reducing load and required reserves or the AS that DPV could provide when coupled with other technologies. While methodologies are inconsistent, the approaches generally focus on methods for calculating changes in necessary operating reserves, and less precision or rules of thumb are applied to the remainder of AS, such as voltage regulation. Operating reserves are typically estimated by determining the reliable capacity for which DPV can be counted on to provide capacity when demanded over the year.

WHY AND HOW VALUES DIFFER

- **System Context:**
    - **Reliability standards and market rules** - The standards and rules for reliability that govern the requirements for grid support services and reserve margins differ. These standards directly impact the potential net value of adding DPV to the system.
    - **Availability of ancillary services market** - Where wholesale electricity markets exist, the estimated value is correlated to the market prices of AS.
    - **Solar characteristics** - The timing of energy production from DPV and it's coincidence with system peaks differs locationally.
    - **Penetration of DPV** - As PV penetrations increase, the value of its reliable capacity decreases and, under standard reliability planning approaches, would increase the amount of system reserves necessary to maintain reliable operations.
    - **System generation mix** - The performance characteristics of the existing generation mix, including the generators ability to respond quickly by increasing or decreasing production, can significantly change the supply value of ancillary services and the value.
- **Methodologies:**
    - **Effective capacity of DPV** - The degree that DPV can be depended on to provide capacity when demanded has a direct effect on the amount of operating reserves that the rest of the system must supply. The higher the "effective capacity," the less operating reserves necessary.
    - **Correlating reduced load with reduced ancillary service needs** - Crossborder (AZ) 2013 calculated a net benefit of DPV based on 1) load reduction & reduced operating reserve requirements; 2) peak demand reduction and utility capacity requirements.
    - **Potential of DPV to provide grid support with technology coupling** - While the primary focus across studies was the impact DPV would have on the need for additional AS, NREL 2008 & AE/CPR 2006 both noted that DPV could provide voltage regulation with smart inverters were installed.

GRID SUPPORT SERVICES BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES



Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.

GRID SUPPORT SERVICES (CONT'D)

Grid Support Services	The potential for DPV to provide grid support services (with technology modifications)
REACTIVE SUPPLY AND VOLTAGE CONTROL	(+/-) PV with an advanced inverter can inject/consume VARs, adjusting to control voltage
FREQUENCY REGULATION	(+/-) Advanced inverters can adjust output frequency; standard inverters may
ENERGY IMBALANCE	(+/-) If PV output < expected, imbalance service is required. Advanced inverters could adjust output to provide imbalance
OPERATING RESERVES	(+/-) Additional variability and uncertainty from large penetrations of DPV may introduce operations forecast error and increase the need for certain types of reserves; however, DPV may also reduce the amount of load served by central generation, thus, reducing needed reserves.
SCHEDULING / FORECASTING	(-) The variability of the solar resource requires additional forecasting to reduce uncertainty

INSIGHTS & IMPLICATIONS

- As with large scale renewable integration, there is still controversy over determining the net change in "ancillary services due to variable generation and much more controversy regarding how to allocate those costs between specific generators or loads." (LBNL 2012)
- Areas with wholesale AS markets enable easier quantification of the provision of AS. Regions without markets have less standard methodologies for quantifying the value of AS.
- One of the most significant differences in reviewed methodological approaches is whether the necessary amount of operating reserves, as specified by required reserve margin, decreases by DPV's capacity value (as determined by ELCC, for example). Crossborder (CA) 2013, E3 2012 and Vote Solar 2005 note that the addition of DPV reduces load served by central generation, thus allowing utilities to reduce procured reserves. Additional analysis is needed to determine whether the required level of reserves should be adjusted in the face of a changing system.
- Studies varied in their assessments of grid support services. APS 2009 did not expect DPV would contribute significantly to spinning or operating reserves, but predicted regulation reserves could be affected at high penetration levels.

LOOKING FORWARD

Increasing levels of distributed energy resources and variable renewable generation will begin to shift both the need for grid support services as well as the types of assets that can and need to provide them. The ability of DPV to provide grid support requires technology modifications or additions, such as advanced inverters or storage, which incur additional costs. However, it is likely that the net value proposition will increase as technology costs decrease and the opportunity (or requirements) to provide these services increase with penetration.

FINANCIAL: FUEL PRICE HEDGE

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VALUE OVERVIEW

DPV produces roughly constant-cost power compared to fossil fuel generation, which is tied to potentially volatile fuel prices. DPV can provide a "hedge" against price volatility, reducing risk exposure to utilities and customers.

APPROACH OVERVIEW

More than half the studies reviewed acknowledge DPV's fuel price hedge benefit, although fewer quantify it and those that do take different, although conceptually similar, approaches.

- In future years when natural gas futures market prices are available, using those NYMEX prices to develop a natural gas price forecast should include the value of volatility.
- In future years beyond when natural gas futures market prices are available, estimate natural gas price and volatility value separately. Differing approaches include:
    - Escalating NYMEX prices at a constant rate, under the assumption that doing so would continue to reflect hedge value (Crossborder (AZ) 2013); or
    - Estimating volatility hedge value separately as the value or an option/swap, or as the actual price adder the utility is incurring now to hedge gas prices (CPR (NJ/PA 2012), NREL 2008).

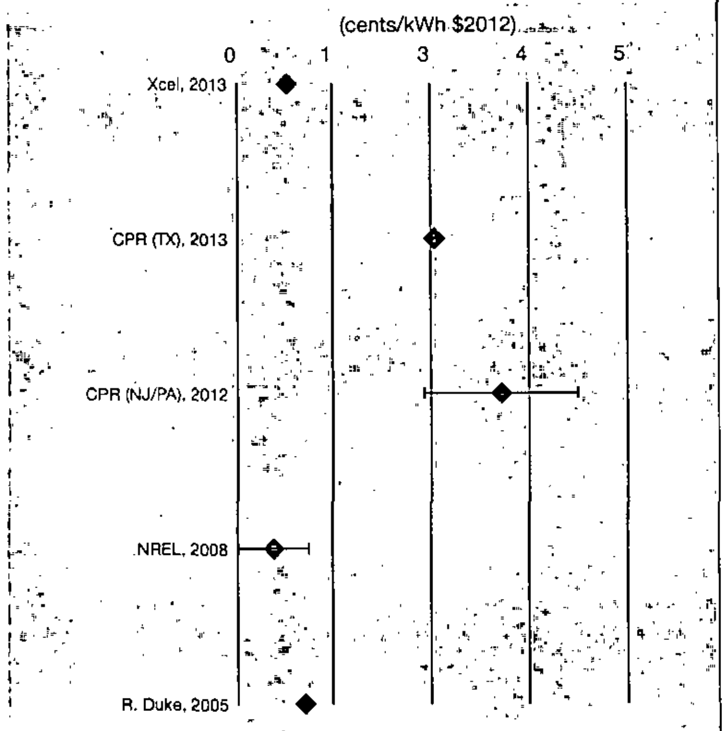
WHY AND HOW VALUES DIFFER

- **System Context:**
    - **Marginal resource characterization** - What resource is on the margin, and therefore how much fuel is displaced varies.
    - **Exposure to fuel price volatility** - Most utilities already hedge some portion of their natural gas purchases for some period of time in the future.
- **Methodologies:**
    - **Approach to estimating value** - While most studies agree that NYMEX futures prices are an adequate reflection of volatility, there is no largely agreed upon approach to estimating volatility beyond when those prices are available.

INSIGHTS & IMPLICATIONS

- NYMEX futures market prices are an adequate reflection of volatility in the years in which it operates.
- Beyond that, volatility should be estimated, although there is no obvious best practice. Further work is required to develop an approach that accurately measures hedge value.

FUEL PRICE HEDGE BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES



Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.

FINANCIAL: MARKET PRICE RESPONSE

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VALUE OVERVIEW

The addition of DPV, especially at higher penetrations, can affect the market price of electricity in a particular market or service territory. These market price effects span energy and capacity values in the short term and long term, all of which are interrelated. Benefits can occur as DPV provides electricity close to demand, reducing the demand for centrally-supplied electricity and the fuel powering those generators, thereby lowering electricity prices and potentially fuel commodity prices. A related benefit is derived from the effect of DPV's contribution at higher penetrations to reshaping the load profile that central generators need to meet. Depending upon the correlation of DPV production and load, the peak demand could be reduced and the marginal generator could be more efficient and less costly, reducing total electricity cost. However, these benefits could potentially be reduced in the longer term as energy prices decline, which could result in higher demand. Additionally, depressed prices in the energy market could have a feedback effect by raising capacity prices.

APPROACH OVERVIEW

While several studies evaluate a market price response of DPV, distinct approaches were employed by E3 2012, CPR (NJ/PN) 2012, and NREL 2008.

WHY AND HOW VALUES DIFFER

- **Methodologies:**
  - **Considering market price effects of DPV in the context of other renewable technologies -** E3 2012 *incorporated market price effect in its high penetration case by adjusting downward the marginal value of* energy that DPV would displace. However, for the purposes of the study, E3 2012 did not add this as a benefit to the avoided cost because they "assume the market price effect would also occur with alternative approaches to meeting [CA's] RPS."
  - **Incorporating capacity effects -**
    - E3 2012 represented a potential feedback effect between the energy and capacity by assuming an energy market calibration factor. That is, it assumes that, in the long run, the CCGT's energy market revenues plus the capacity payment equal the fixed and variable costs of the CCGT. Therefore, a CCGT would collect more revenue through the capacity and energy markets than is needed to cover its costs, and a decrease in energy costs would result in a relative increase in capacity costs.
    - CPR (NJ/PA) 2012 incorporates market price effect "by reducing demand during the high priced hours [resulting in] a cost savings realized by all consumers." They note "that further investigation of the methods may be warranted in light of two arguments...that the methodology does address induced increase in demand due to price reductions, and that it only addresses short-run effects (ignoring the impact on capacity markets)."

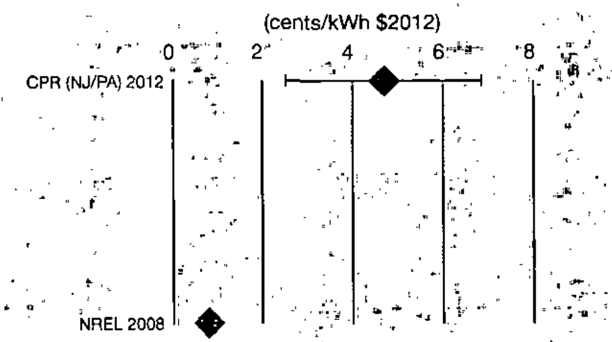
INSIGHTS & IMPLICATIONS

- The market price reduction value only assesses the initial market reaction of reduced price, not subsequent market dynamics (e.g. increased demand in response to price reductions, or the impact on the capacity market), which has to be studied and considered, especially in light of higher penetrations of DPV.

LOOKING FORWARD

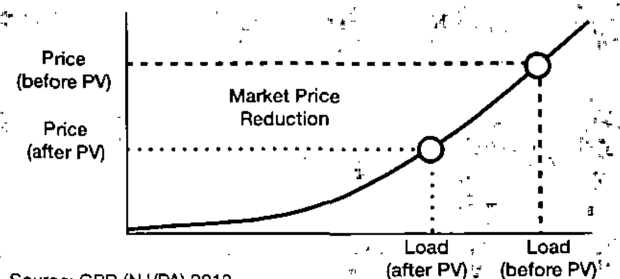
Technologies powered by risk-free fuel sources (such as wind) and technologies that increase the efficiency of energy use and decrease consumption would also have similar effects.

MARKET PRICE RESPONSE BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES



Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs. Also, E3 2012 is not included in this chart because this study did not provide an itemized value for market price response.

MARKET PRICE VS. LOAD



Source: CPR (NJ/PA) 2012

SECURITY: RELIABILITY AND RESILIENCY

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VALUE OVERVIEW

The grid security value that DPV could provide is attributable to three primary factors, the last of which would require coupling DPV with other technologies to achieve the benefit:

1) The potential to reduce outages by reducing congestion along the T&D network. Power outages and rolling blackouts are more likely when demand is high and the T&D system is stressed.
2) The ability to reduce large-scale outages by increasing the diversity of the electricity system's generation portfolio with smaller generators that are geographically dispersed.
3) The benefit to customers to provide back-up power sources available during outages through the combination of PV, control technologies, inverters and storage.

APPROACH OVERVIEW

While there is general agreement across studies that integrating DPV near the point of use will decrease stress on the broader T&D system, most studies do not calculate a benefit due to the difficulty of quantification. CPR 2012 and 2011 did represent the value as the value of avoided outages based on the total cost of power outages to the U.S. each year, and the perceived ability of DPV to decrease the incidence of outages.

INSIGHTS & IMPLICATIONS

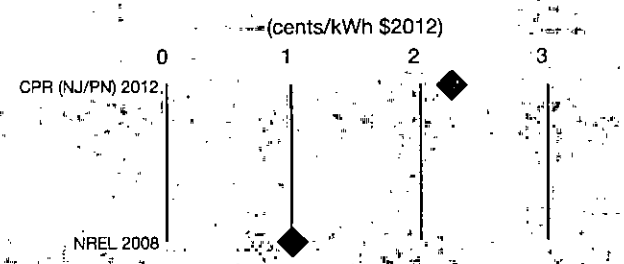
- The value of increased reliability is significant, but there is a need to quantify and demonstrate how much value can be provided by DPV. Rules-of-thumb assumptions and calculations for security impacts require significant analysis and review.

- Opportunities to leverage combinations of distributed technologies to increase customer reliability are starting to be tested. The value of DPV in increasing suppling power during outages can only be realized if DPV is coupled with storage and equipped with the capability to island itself from the grid, which come at additional capital cost.

LOOKING FORWARD

Any distributed resources that can be installed near the end user to reduce use of, and congestion along, the T&D network could potentially reduce transmission stress. This includes technologies that allow energy to be used more efficiently or at different times, reducing the quantity of electricity traveling through the T&D network (especially during peak hours). Any distributed technologies with the capability to be islanded from the grid could also play a role.

RELIABILITY AND RESILIENCY BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES



Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.

Disruption Value* Range by Sector
(cents/kWh $2012)

Sector	Min	Max
Residential	0.028	0.41
Commercial	11.77	14.40
Industrial	0.4	1.99

Source: The National Research Council, 2010

*Disruption value is a measure of the damages from outages and power-quality events based on the increased probability of these events occurring with increasing electricity consumption.

ENVIRONMENT: CARBON DIOXIDE

VALUE OVERVIEW

The benefits of reducing carbon emissions include (1) reducing future compliance costs, carbon taxes, or other fees, and (2) mitigating the heath and ecosystem damages potentially caused by climate change.

APPROACH OVERVIEW

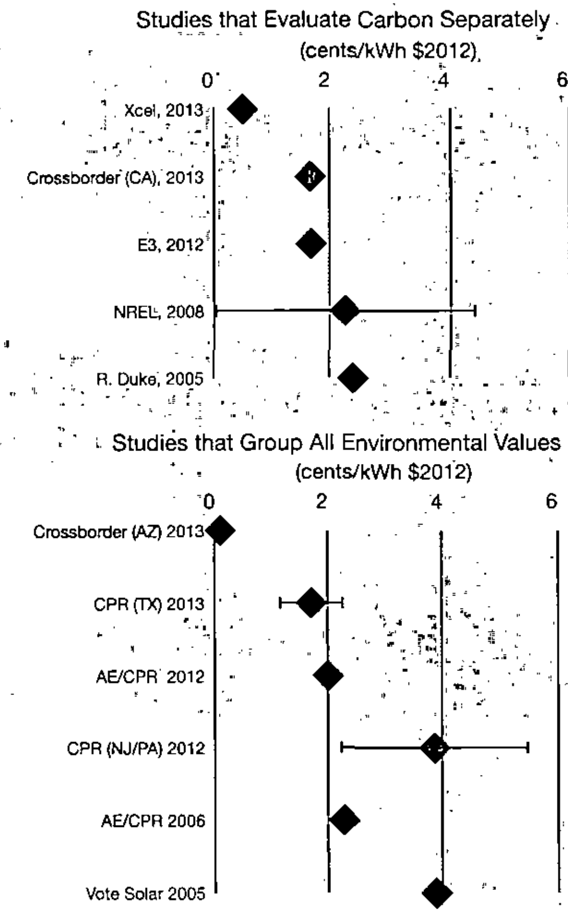
By and large, studies that addressed carbon focused on the compliance costs or fees associated with future carbon emissions, and conclude that carbon reduction can increase DPV's value by more than two cents per kilowatt-hour, depending heavily on the price placed on carbon. While there is some agreement that carbon reduction provides value and on the general formulation of carbon value, there are widely varying assumptions, and not all studies include carbon value.

Carbon reduction benefit is the amount of carbon displaced times the price of reducing a ton of carbon. The amount of carbon displaced is directly linked to the amount of energy displaced, when it is displaced, and the carbon intensity of the resource being displaced.

WHY AND HOW VALUES DIFFER

- **System Context:**
  - **Marginal resource characterization** - Different resources may be on the margin in different regions or with different solar penetrations. Carbon reduction is significantly different if energy is displaced from coal, gas combined cycles, or gas combustion turbines.
- **Input Assumptions:**
  - **Value of carbon reduction** - Studies have widely varying assumptions about the price or carbon. Some studies base price on reported prices in European markets, others on forecasts based on policy expectations, others on a combination. The increased uncertainty around U.S. Federal carbon legislation has made price estimates more difficult.
  - **Heat rates of marginal resources** - The assumed efficiency of the marginal power plant is directly correlated to amount of carbon displaced by DPV.
- **Methodologies:**
  - **Adder vs. stand-alone value** - There is no common approach to whether carbon is represented as a stand-alone value (for example, NREL 2008 and E3 2012) or as an adder to energy value (for example, APS 2013).
  - **Marginal resource characterization** - Just as with energy (which is directly linked to carbon reduction), studies take one of three general approaches: (1) DPV displaces energy from a gas plant, generally a combined cycle, (2) DPV displaces energy from one type of plant (generally a combined cycle) off-peak and a different type of plant (generally a combustion turbine) on-peak, (3) DPV displaces whatever resource is on the margin during every hour of the year, based on a dispatch analysis.

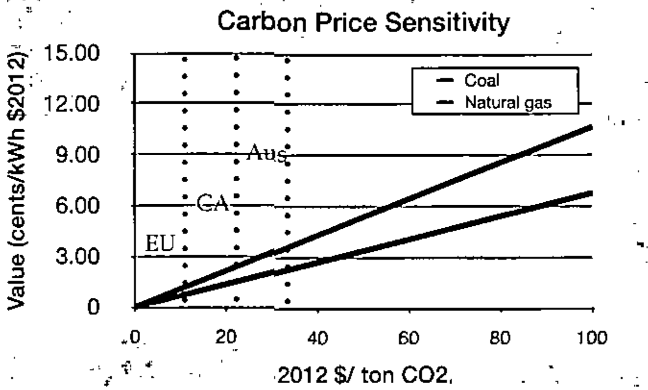
ENVIRONMENTAL BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES

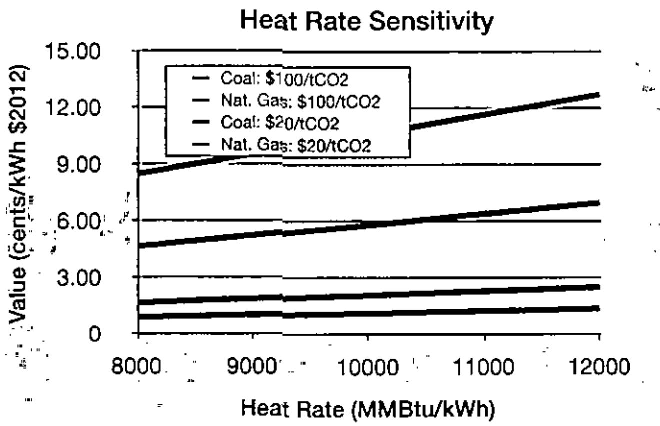


Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.

ENVIRONMENT: CARBON DIOXIDE
(CONT'D)

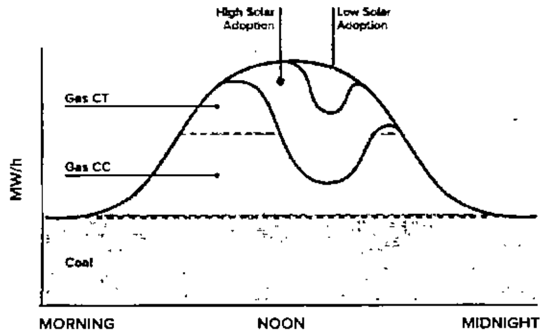
SENSITIVITY TO KEY INPUT ASSUMPTIONS





INSIGHTS & IMPLICATIONS

- *Just as with energy value, carbon value depends heavily on what the marginal resource is that is being* displaced. The same determination of the marginal resource should be used to drive both energy and carbon values.



The amount of carbon DPV displaces depends on the dispatch order of other resources, when the solar is generated, and how much is generated.

- While there is little agreement on what the $/ton price of carbon is or should be, it is likely non-zero.

LOOKING FORWARD

While there has been no federal action on climate over the last few years, leading to greater uncertainty about potential future prices, many states and utilities continue to value carbon as a reflection of assumed benefit. There appears to be increasing likelihood that the U.S. Environmental Protection Agency will take action to limit emissions from coal plants, potentially providing a more concrete indicator of price.

ENVIRONMENT: OTHER FACTORS

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In addition to carbon, DPV has several other environmental benefits (or potentially costs) that, while commonly acknowledged, are included in only a few of the studies reviewed here. That said, there is a significant body of thought for each outside the realm of DPV cost/benefit valuation, some of which is referenced below.

CRITERIA AIR POLLUTANTS

SUMMARY: Criteria air pollutants (NO_X, SO_2, and particulate matter) released from the burning of fossil fuels can produce both health and ecosystem damages. The economic cost of these pollutants is generally estimated as:

1. The compliance costs of reducing pollutant emissions from power plants, or the added compliance costs to further decrease emissions beyond some baseline standard; and/or

2. The estimated cost of damages, such as medical expenses for asthma patients or the value of mortality risk, which attempts to measure willingness to pay for a small reduction in risk of dying due to air pollution.

VALUE: Crossborder (AZ) 2013 estimated the value of criteria air pollutant reductions, based on APS's Integrated Resource Plan, as $0.365/MWh, and NREL 2008 as $0.2-14/MWh (2012$). CPR (NJ/PA) 2012 and AE/CPR 2012 also acknowledged criteria air pollutants, but estimate cost based on a combined environmental value.

RESOURCES:

Epstein, P., Buonocore, J., Eckerle, K. et al., *Full Cost Accounting for the Life Cycle of Coal*, 2011.

Muller, N., Mendelsohn, R., Nordhaus, W., *Environmental Accounting for Pollution in the US Economy.* American Economic Review 101, Aug. 2011. pp. 1649 - 1675.

National Research Council. *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use*, 2010.

AVOIDED RENEWABLE PORTFOLIO STANDARD (RPS)

SUMMARY: Investments in DPV can help the utility meet a state Renewable Portfolio Standards (RPS) / Renewable Energy Standards (RES) in two ways:

1. As DPV is installed and energy use from central generation correspondingly decreases, the amount of renewable energy the utility is required to purchase to meet an RPS/RES decreases.

2. Depending on the RPS/RES requirements, customer investment in DPV can translate into direct investments in renewables that utilities do have to make if they are able to receive credit, such as through Renewable Energy Certificates (RECs).

VALUE: Crossborder (AZ) 2013 estimated the avoided RPS cost, based on the difference between the revenue requirements for a base scenario and a high renewables scenario in APS's Integrated Resource Plan, as $45/MWh. Crossborder (CA) estimated the avoided RPS cost, based on the cost difference forecast between RPS-eligible resources and the wholesale market prices, at $50/MWh.

RESOURCES:

Beach, R., McGuire, P., *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service.* Crossborder Energy May, 2013.

Beach, R., McGuire, P., *Evaluating the Benefits and Costs of Net Energy Metering for Residential Customers in California.* Crossborder Energy, Jan. 2013.

ENVIRONMENT: OTHER FACTORS

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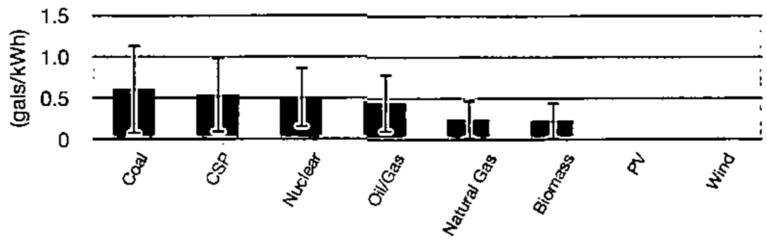
In addition to carbon, DPV has several other environmental benefits (or potentially costs) that, while commonly acknowledged, are included in only a few of the studies reviewed here. That said, there is a significant body of thought for each outside the realm of DPV cost/benefit valuation, some of which is referenced below.

WATER

SUMMARY: Coal and natural gas power plants withdraw and consume water primarily for cooling. Approaches to valuing reduced water usage have focused on the cost or value of water in competing sectors, potentially including municipal, agricultural, and environmental/recreational uses.

WATER CONSUMPTION BY TECHNOLOGY



Source: Fthenakis

VALUE: The only study reviewed that explicitly values water reduction is Crossborder (AZ) 2013, which estimates a $1.084/MWh value based on APS's Integrated Resource Plan.

RESOURCES:

Tellinghulsen, S., *Every Drop Counts.* Western Resources Advocates, Jan. 2011.

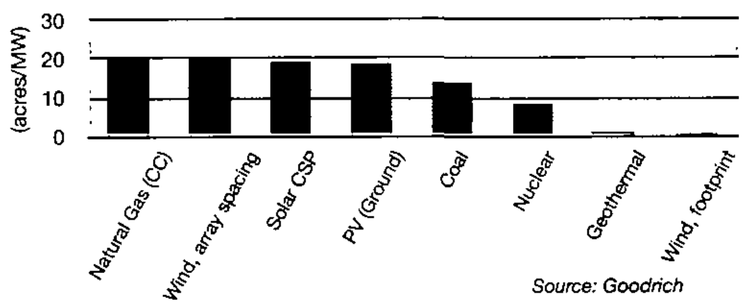
Fthenakis, V., Hyungl, C., *Life-cycle Use of Water in U.S. Electricity Generation.* Renewable and Sustainable Energy Review 14, Sept. 2010. pp.2039-2048.

LAND

SUMMARY: DPV can impact land in three ways:

1) Change in property value with the addition of DPV,
2) Land requirement for DPV installation, or
3) Ecosystem impacts of DPV installation.

LIFE-CYCLE LAND USE BY TECHNOLOGY



Source: Goodrich

VALUE: None of the studies reviewed explicitly estimate land impacts.

RESOURCES:

Goodrich et al. Residential, Commercial, and Utility Scale Photovoltaic (V) System Prices in the United States: Current Drivers and Cost-Reduction Opportunities. NREL. February 2012. Pages 14, 23—28

SOCIAL: ECONOMIC DEVELOPMENT

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VALUE OVERVIEW

The assumed social value from DPV is based on any job and economic growth benefits that DPV brings to the economy, including jobs and higher tax revenue. The value of economic development depends on number of jobs created or displaced, as measured by a job multiplier, as well as the value of each job, as measured by average salary and/or tax revenue.

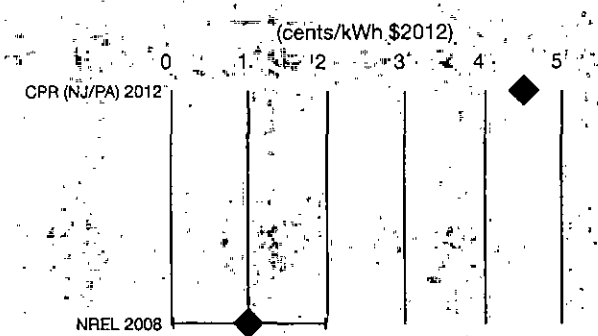
APPROACH OVERVIEW

Very few studies reviewed quantify employment and tax revenue value, although a number of them acknowledge the value. CPR (NJ/PN) 2012 calculated job impact based on enhanced tax revenues associated with the net job creation for solar vs conventional power resources. The 2011 study included increased tax revenue, decreased unemployment, and increased confidence for business development economic growth benefits, but only quantified the tax revenue benefit.

IMPLICATIONS AND INSIGHTS

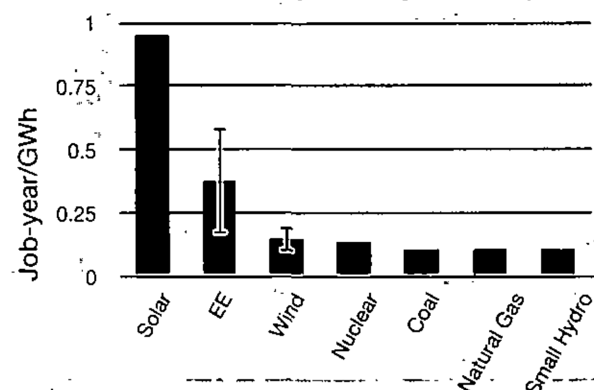
- There is significant variability in the range of job multipliers.
- Many of the jobs created from PV, particularly those associated with installation, are local, so there can be value to society and local communities from growth in quantity and quality of jobs available. The locations where jobs are created are likely not the same as where jobs are lost. While there could be a net benefit to society, some regions could bear a net cost from the transition in the job market.
- While employment and tax revenues have not generally been quantified in studies reviewed, E3 2011 recommends an input-output modeling approach as an adequate representation of this value.

ECONOMIC DEVELOPMENT BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES



Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.

Job Multipliers by Industry



Sources: Wei, 2010

RESOURCES:

Wei, M., Patadia, S., and Kammen, D., Putting Renewables and Energy Efficiency to Work: How Many Jobs Can the Energy Industry Generate in the US? Energy Policy 38, 2010. pp. 919-931.

Brookings Institute, Sizing the Clean Economy: A National and Regional Green Jobs Assessment, 2011.

STUDY OVERVIEWS

04

SECTION STRUCTURE

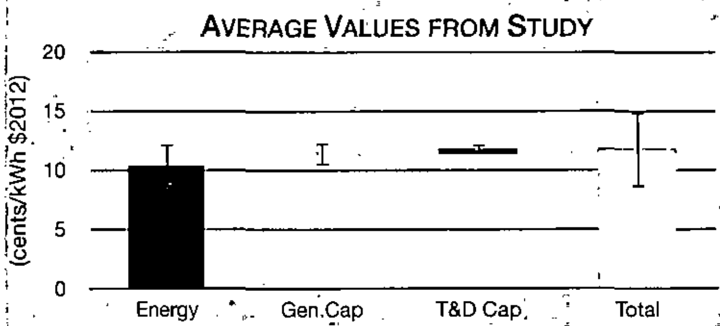
KEY COMPONENTS INCLUDED IN EACH STUDY OVERVIEW

STUDY CHARACTERISTICS	
STUDY OBJECTIVE	*A brief overview of the stated purpose of the study*
GEOGRAPHIC FOCUS	*Geographic region analyzed*
SYSTEM CONTEXT	*Relevant characteristics of the electricity system analyzed*
LEVEL OF SOLAR ANALYZED	*Solar penetrations analyzed, by energy or capacity*
STAKEHOLDER PERSPECTIVE	*Stakeholder perspectives analyzed (e.g., participant, ratepayer, society)*
GRANULARITY OF ANALYSIS	*Level of granularity reflected in the analysis as defined by:* • *Solar characterization - How the solar generation profile is established (e.g., actual insolation data v. modeled, time correlated to load)* • *Marginal resource/losses characterization - Whether the marginal resources and losses are calculated on a marginal hourly basis v. average* • *Geographic granularity - Approach to estimating locationally-dependent benefits or costs (e.g., distribution feeders)*
TOOLS USED	*Key modeling tools used in the analysis*

Highlights

The Highlights section includes key observations about the study's approach, key drivers of results, and findings.

OVERVIEW OF VALUE CATEGORIES



The chart above depicts the average values by category explored in each study.

The Overview of Value Categories section includes brief assessments of the study's approach, relevant assumptions, and findings for each value category included.

DISTRIBUTED RENEWABLE ENERGY OPERATING IMPACTS & VALUATION STUDY

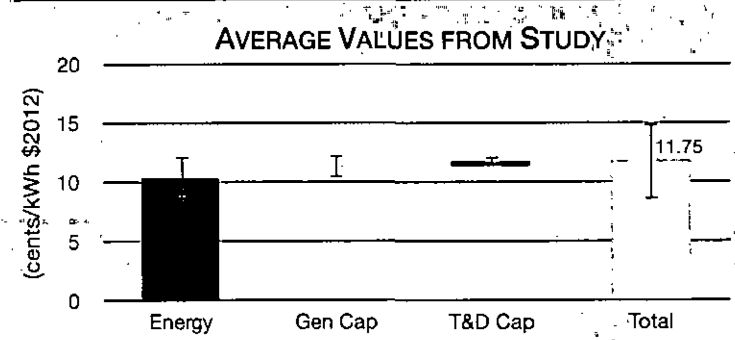
eLab Electricity Innovation Lab ROCKY MOUNTAIN INSTITUTE

STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To determine the potential value of DPV for Arizona Public Service, and to understand the likely operating impacts.
GEOGRAPHIC FOCUS	Arizona Public Service territory
SYSTEM CONTEXT	Vertically integrated IOU, 15% RPS by 2025 with 30% distributed resource carveout
LEVEL OF SOLAR ANALYZED	0.2-16% by 2025 (by energy)
STAKEHOLDER PERSPECTIVE	Ratepayers
GRANULARITY OF ANALYSIS	• Solar characterization - Hourly TMY data, determined to be good approximation of calendar year data in a comparison • Marginal resource/losses characterization - Calculated based on hourly PROMOD simulation; theoretical hourly loss analysis; actual APS investment plan • Geographic granularity - Screening analysis of specific feeders; example constrained area and greenfield area analyzed
TOOLS USED	SAM 2.0; ABB's Feeder-All; EPRI's Distribution System Simulator; PROMOD

Highlights

- Value was measured incrementally in 2010, 2015, and 2025. The study approach combined system modeling, empirical testing, and information review, and represents one of the more technically rigorous approaches of reviewed studies.
- A key methodological assumption in the study is that generation, transmission, and distribution capacity value can only be given to DPV when it actually defers or avoids a planned investment. The implications are that a certain minimum amount of DPV must be installed in a certain time period (and in a certain location for distribution capacity) to create value.
- The study determines that total value decreases over time, primarily driven by decreasing capacity value. Increasing levels of DPV effectively pushes the system peak to later hours.
- The study acknowledged but did not quantify a number of other values including job creation, a more sustainable environment, carbon reduction, and increased worker productivity.

OVERVIEW OF VALUE CATEGORIES



**this chart represents the present value of 2025 incremental value, not a levelized cost*

Energy: Energy provides the largest source of value to the APS system. Value is calculated based on a PROMOD hourly commitment and dispatch simulation. DPV reduces fuel, purchased power requirements, line losses, and fixed O&M. The natural gas price forecast is based on NYMEX forward prices with adjustment for delivery to APS's system.

Generation Capacity: There is little, but some, generation capacity value. Generation capacity value does not differ based on the geographic location of solar, but generation capacity investments are "lumpy", so a significant amount of solar is needed to displace it.

Capacity value includes benefits from reduced losses. Capacity value is determined by comparing DPV's dependable capacity (determined as the ELCC) to APS's generation investment plan.

T&D Capacity: There is very little distribution capacity value, and what value exists comes from targeting specific feeders. Solar generation peaks earlier in the day than the system's peak load, DPV only has value if it is on a feeder that is facing an overloaded condition, and DPV's dependable capacity diminishes as solar penetration increases. Distribution value includes capacity, extension of service life, reduction in equipment sizing, and system performance issues.

There is little, but some, transmission capacity value since value does not differ based on the geographic location of solar, but transmission investments are "lumpy", so a significant amount of solar is needed to displaced it. Transmission value includes capacity and potential detrimental impacts to transient stability and spinning resources (i.e., ancillary services).

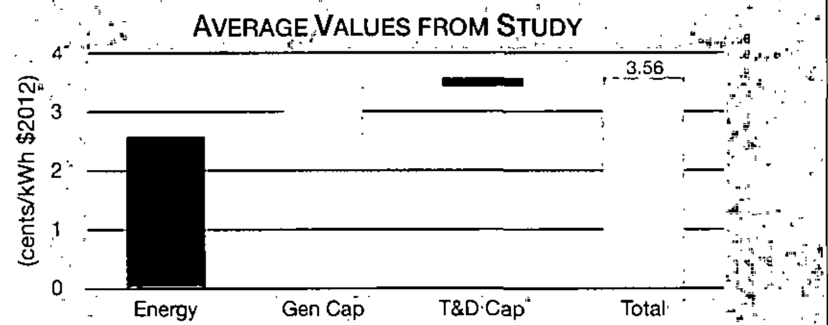
T&D capacity value includes benefits from reduced losses, modeled with a combination of hourly system-wide and feeder-specific modeling. T&D capacity value is determined by comparing DPV's dependable capacity to APS's T&D investment plan. For T&D, as compared to generation, dependable capacity is determined as the level of solar output that will occur with 90% confidence during the daily five hours of peak during summer months.

Study Characteristics	
Study objective	To update the valuation of future DPV systems in the Arizona Public Service (APS) territory installed after 2012.
Geographic focus	Arizona Public Service territory
System context	Vertically integrated IOU, 15% RPS by 2025 with 30% distributed resource carve out, peak extends past sunset
Level of solar analyzed	4.5-16% by 2025 (by energy)
Stakeholder perspective	Ratepayers
Granularity of analysis	• Solar characterization - Hourly 30-year TMY data; coupled with production characteristics of actual installed systems • Marginal resource/losses characterization - Calculated based on hourly PROMOD simulation and APS investment plan as in 2009 study; average energy loss and system peak demand loss factors as recorded by APS • Geographic granularity - Screening analysis of existing feeders with >10% PV; based on that, determination of number of feeders where PV could reduce peak load from above 90% to below 90%
Tools used	PVWatts; EPRI's DSS Distribution Feeder Model; PROMOD

Highlights

- Value was measured incrementally in 2015, 2020, and 2025.
- DPV provides less value than in APS's 2009 study, due to changing power market and system conditions. Energy generation and wholesale purchase costs have decreased due to lower natural gas prices. Expected CO_2 costs are significantly lower due to decreased likelihood of federal legislation. Load forecasts are lower, meaning reduced generation, distribution and transmission capacity requirements.
- The study notes the potential for increased value (primarily in T&D capacity) if DPV can be geographically targeted in sufficient quantities. However, it notes that actual deployment since the 2009 study does not show significant clustering or targeting.
- Like the 2009 study, capacity value is assumed to be based on DPV's ability to defer planned investments, rather than assuming every installed unit of DPV defers capacity.

Overview of Value Categories



this chart represents the present value of 2025 incremental value, not a levelized cost

Energy: Energy provides the largest source of value to the APS system. Value is calculated based on a PROMOD hourly commitment and dispatch simulation. DPV reduces fuel, purchased power requirements, line losses, and fixed O&M. The natural gas price forecast is based on NYMEX forward prices with adjustment for delivery to APS's system. Energy losses are included as part of energy value, and unlike the 2009 report, are based on a recorded average energy loss.

Generation Capacity: Generation capacity value is highly dependent on DPV's dependable capacity during peak. Generation capacity value is based on PROMOD simulations, and results in the deferral of combustion turbines. Benefits from avoided energy losses are included as part of capacity value, and unlike the 2009 report, are based on a recorded peak demand loss. Like the 2009 study, generation capacity value is based on an ELCC calculation.

T&D Capacity: The study concludes that there are an insufficient number of feeders that can defer capacity upgrades based on non-targeted solar PV installations to determine measurable capacity savings. Distribution capacity savings can only be realized if distributed solar systems are installed at adequate penetration levels and located on specific feeders to relieve congestion or delay specific projects, but solar adoption has been geographically dispersed. Distribution value includes reduced losses, capacity, extended service life, and reduced equipment sizing.

Transmission capacity value is highly dependent on DPV's dependable capacity during peak. No transmission projects can be deferred more than one year, and none past the target years. As with the 2009 study, DPV dependable capacity for the purposes of T&D benefits is calculated based on a 90% confidence of generation during peak summer hours. Benefits from avoided energy losses are included.

CROSSBORDER ENERGY, 2013

THE BENEFITS AND COSTS OF SOLAR DISTRIBUTED GENERATION FOR ARIZONA PUBLIC SERVICE

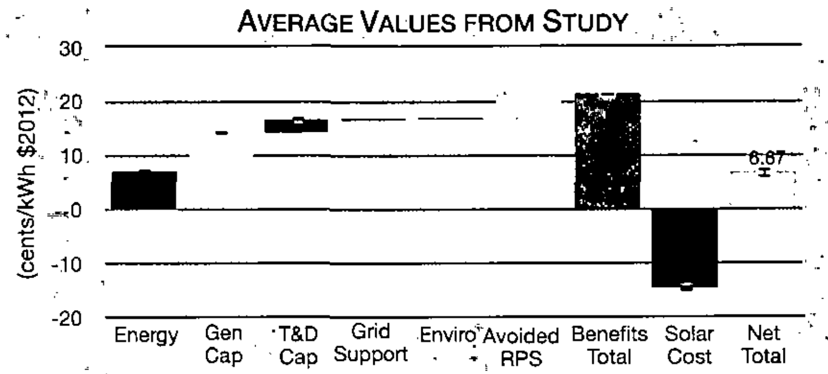
Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To determine how demand-side solar will impact APS's ratepayers; a response to the APS 2013 study.
GEOGRAPHIC FOCUS	Arizona Public Service territory
SYSTEM CONTEXT	Vertically integrated IOU, 15% RPS by 2025
LEVEL OF SOLAR ANALYZED	DPV likely to be installed between 2013-2015; estimated here to be approximately 1.5%
STAKEHOLDER PERSPECTIVE	Ratepayers
GRANULARITY OF ANALYSIS	• Solar characterization - Not stated • Marginal resource/losses characterization - For energy, expected operating cost of a CT in peak months and CC in non-peak months; for capacity, fixed costs of a CT; marginal line loss factor from APS 2009 • Geographic granularity - Assumption that distribution investment can be deferred on 50% of feeders, based on APS 2009 conclusion that 50% of feeders show potential for reducing peak demand
TOOLS USED	Secondary analysis based on SAIC and APS detailed modeling

Highlights

- The benefits of DPV on the APS system exceed the cost by more than 50%. Key methodological differences between this study and the APS 2009 and 2013 studies include:
  - Determining value levelized over 20 years, as compared to incremental value in test years.
  - Crediting capacity value to every unit of solar DG installed, rather than requiring solar DG to be installed in "lumpy" increments.
  - Using ELCC to determine dependable capacity for generation, transmission, and distribution capacity values, as compared to using ELCC for generation capacity and a 90% confidence during peak summer hours for T&D capacity.
  - Focusing on solar installed over next few years years, rather than examining whether there is diminishing value with increasing penetration.
- The study notes that DPV must be considered in the context of efficiency and demand response—together they defer generation, transmission, and distribution capacity until 2017.

OVERVIEW OF VALUE CATEGORIES



Energy: Avoided energy costs are the most significant source of value. APS's long-term marginal resource is assumed to be a combustion turbine in peak months and a combined cycle in off-peak months, and avoided energy is based on these resources. The natural gas price forecast is based on NYMEX forward market gas prices, and the study determines that it adequately captures the fuel price hedge benefit. Key assumptions: $15/ton carbon adder, 12.1% line losses included in the energy value.

Generation Capacity: Generation capacity value is calculated as DPV dependable capacity (based on DPV's near-term ELCC from APS's 2012 IRP) times the fixed costs of a gas combustion turbine. Every installed unit of DPV receives that capacity value, based on the assumption that, when coupled with efficiency and demand response, capacity would have otherwise been needed before APS's planned investment.

T&D Capacity: T&D capacity value is calculated as DPV dependable capacity (ELCC) times APS's reported costs of T&D investments. Like generation capacity, every installed unit is credited with T&D capacity, with the assumption that 50% of distribution feeders can see deferral benefit. The study notes that APS could take a proactive approach to targeting DPV deployment, thereby increasing distribution value.

Grid Support (Ancillary Services): DPV in effect reduces load and therefore reduces the need for ancillary services that would otherwise be required, including spinning, non-spinning, and capacity reserves.

Environmental: DPV effectively reduces load and therefore reduces environmental impacts that would otherwise be incurred. Lower load means reduced criteria air pollutant emissions and lower water use (carbon is included as an adder to energy value).

Renewable Value: DPV helps APS meet its Renewable Energy Standard, thereby lowering APS's compliance costs.

Solar Cost: Since the study takes a ratepayer perspective, costs included are lost retail rate revenues, incentive payments, and integration costs.

XCEL ENERGY FOR PUBLIC SERVICE COMPANY OF COLORADO, 2013
COSTS AND BENEFITS OF DISTRIBUTED SOLAR GENERATION ON THE PUBLIC SERVICE COMPANY OF COLORADO SYSTEM

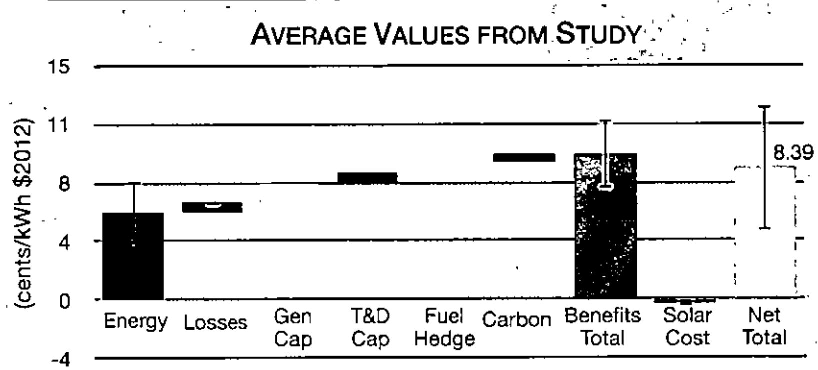
Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To determine the costs and benefits of DPV on the Public Service Company of Colorado's electric power supply system at current penetration levels and projections for near-term penetration levels.
GEOGRAPHIC FOCUS	Public Service Company of Colorado's territory
SYSTEM CONTEXT	Vertically integrated IOU, 30% RPS by 2020 (includes DG standard)
LEVEL OF SOLAR ANALYZED	2012 DPV solar capacity: 59 MW; Est penetration in 2014: 140 MW installed by 2014
STAKEHOLDER PERSPECTIVE	System (excludes participant expenses (PV cost), solar program administration costs, or program incentive payments)
GRANULARITY OF ANALYSIS	• Solar characterization - Single TMY2 hourly generation profile weighted to represent entire 59 MW of DPV on PSCO's system used to calculate avoided energy costs & certain components of distribution system analysis; Historical meter data from 9 PV systems in 2009, 14 systems in 2010 (each >250 kW) used to estimate DPV capacity credit • Marginal resource/losses characterization - Calculated based on hourly PROMOD simulation; theoretical hourly loss analysis • Geographic granularity - Hourly feeder level data from small subset of feeders extrapolated to system
TOOLS USED	ProSym; NREL's TMY2 data sets using PV Watts

Highlights

- The study concludes that the most significant avoided cost from DPV (>90%) is from avoided energy costs.
- Energy value was calculated by comparing ProSym simulations with and without DPV, and the results were highly sensitive to assumed natural gas price forecasts. To estimate annual avoided energy costs, ProSym modeling used a single TMY2 generation profile (weighted by distribution of PV across PSCO's system), which was non-serially correlated with system load data.
- For the study, Xcel updated its ELCC calculations that are used to estimate capacity credit for DPV. In comparison to its previous 2009 ELCC study, the updated capacity credit for DPV across the four solar zones used is roughly 30% lower. The capacity credits range from 27%-32% for fixed installations and 40%-46% for tracking PV.

OVERVIEW OF VALUE CATEGORIES



Energy: Costs are calculated on a marginal basis using ProSym hourly commitment and dispatch simulation using the TMY2 data set. The variable costs include fuel, variable O&M, and generation unit start costs. ProSym simulation implies DPV tends to primarily displace generation that is blend of an efficient CC unit (7 MMBtu/MWh) and a less efficient CT (10 MMBtu/MWh) through 2035. It is noted that, through 2017, DPV displaces a mix of gas-fired and coal-fired generation (before coal is retired in 2017).

System Losses: Avoided T&D lines losses were assumed to achieve savings in energy, emissions, fuel hedge value and generation capacity. Distribution line losses were estimated using actual hourly feeder load data for the 58 feeders that represent 55% of DPV generation, and using an estimated value for the remainder. Average distribution losses were used to estimate savings from energy, emission & hedge value, and on a peak basis for generation capacity. Transmission line losses, based on annual, DPV generation-weighted values, were used to calculate energy, emissions, and hedge value, whereas avoided generation capacity was based on losses incurred across top 50 load hours.

Generation Capacity: Avoided generation capacity costs are based on the market price of capacity until 2017, and after that (because of incremental need) based on the economic carrying charge of a generic CT's capital and fixed O&M costs. The avoided generation capacity cost is credited to DPV based on a ELCC study (historical system load and solar generation patterns for 2009 and 2010).

T&D Capacity: DPV is assumed to defer distribution feeder capital investment by 1 to 2 years only if the existing feeder's peak load is at or near the feeder's capacity and the feeder's peak load is decreased by ~10%.

Fuel Price Hedge Value: While the study notes the approach taken in other benefit/ cost studies to estimate fuel price hedge value from NYMEX fuel price forecasts, it is not explicitly stated how the fuel price hedge was ultimately estimated.

Carbon: Annual tons of CO_2 emissions avoided by DPV as calculated by the ProSym avoided cost case simulations. Change in marginal emissions over time driven by planned changes in generation fleet (primarily retirement of 1,300 MW coal in 2017).

Solar Cost: Defined as "Integration Costs," or "costs that DPV adds to the overall cost of operating the Public Service power supply system based on inefficiencies that arise when the actual net load differs from the day-ahead forecasted net load." These costs are composed of electricity production costs levelized over 20 years.

STUDY CHARACTERISTICS	
STUDY OBJECTIVE	"To perform a cost-effectiveness evaluation of the California Solar Initiative (CSI) in accordance with the CSI Program Evaluation Plan."
GEOGRAPHIC FOCUS	California
SYSTEM CONTEXT	Study: CSI program, retail net metering CA: 33% RPS, ISO market
LEVEL OF SOLAR ANALYZED	1,940 MW program goal (<1% of 2016 peak load)
STAKEHOLDER PERSPECTIVE	Participants (DPV customers), Ratepayers, Program Administrator, Total Resource, Society
GRANULARITY OF ANALYSIS	• Solar characterization - Hourly PV output profiles based on metered and simulated PV output data • Marginal resource/losses characterization - Energy: historical hourly day-ahead market price shapes (CAISO); Capacity: fixed cost of a new CT less net energy, AS revenues (see Overview box); Energy loss factors by TOU *period, season; Capacity loss factors at peak periods* • Geographic granularity - Major climate zones for each IOU; costs from utility rate case filings used as proxy for long-run marginal cost T&D investment avoided
TOOLS USED	E3 Avoided Cost Calculator (2011)

Highlights

- The study concludes that DPV is not expected to be cost-effective from a total resource or rate impact perspective during the study period, but that participant economics will not hinder CSI adoption goals. Program incentives support participant economics in the short-run, but DPV is expected to be cost-effective for many residential customers without program incentives by 2017. The study suggests that the value of non-economic benefits of DPV should be explored to determine if and how they provide value to California.

- The study focuses on seven benefits including energy, line losses, generation capacity, T&D capacity, emissions, ancillary services, and avoided RPS purchases. It focuses on costs including net energy metering bill credits, rebates/incentives, utility interconnection, costs of the DG system, net metering costs, and program administration.

- The study assesses hourly avoided costs in each of California's 16 climate zones to reflect varying costs in those zones, and calculates benefits and costs as 20-year levelized values. It uses E3's avoided cost model.

OVERVIEW OF VALUE CATEGORIES

This study assesses overall cost-effectiveness based on five cost tests (participant cost test, ratepayer impact measure, program administrator cost, total resource cost, and societal cost) as defined in the California Standard Practices Manual, and presents total rather than itemized results. Therefore, individual results are not shown here in a chart.

Energy: Hourly wholesale value of energy measured at the point of wholesale energy transaction. Natural gas price is based on NYMEX forward market and then on a long-run forecast of natural gas prices.

System Losses: Losses between the delivery location and the point of wholesale energy transaction. Losses scale with energy value, and reflect changing losses at peak periods.

Generation Capacity: Value of avoiding new generation capacity (assumed to be a gas combustion turbine) to meet system peak loads, including additional capacity avoided due to decreased energy losses. DPV receives the full value of avoided capacity after the resource balance year. Value is less in the short-run (before the resource balance year) because of CAISO's substantial planning reserve margin.

T&D Capacity: Value of deferring T&D capacity to meet peak loads.

Grid Support Services (Ancillary Services): Value based on historical ancillary services market prices, scaled with the price of natural gas. Individual ancillary services included are regulation up, regulation down, spinning reserves, and non-spinning reserves, and value is based on how a load reduction affects the procurement of each AS.

Avoided RPS: Value is the incremental avoided cost of purchasing renewable resources to meet California's RPS.

Environmental: Value of CO_2 reduction, with $/ton price based on a meta-analysis of forecasts. Unpriced externalities (primarily health effects) were valued at $0.01-0.03/kWh based on secondary sources.

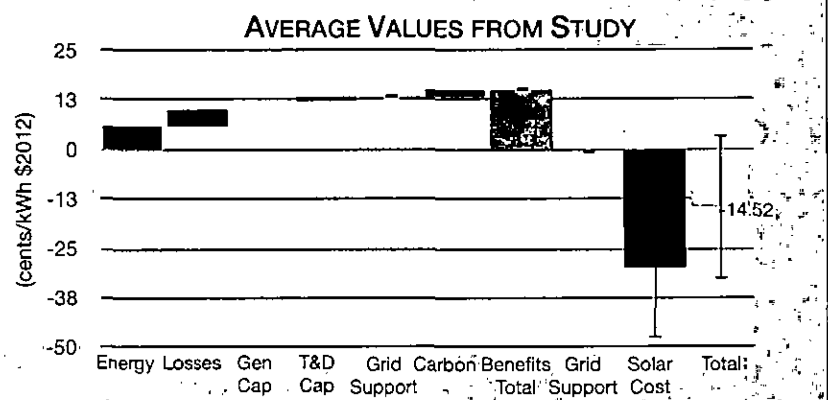
Social: The study acknowledges that customers who install DPV may also install more energy efficiency, but does not attempt to quantify that value. The study also acknowledges potential benefits associated with employment and tax revenues and suggests that an input-output model would be an appropriate approach, although these benefits are not quantified in this study.

STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To estimate the technical potential of local DPV in California, and the associated costs and benefits.
GEOGRAPHIC FOCUS	California
SYSTEM CONTEXT	California's 3 investor-owned utilities (IOU): PG&E, SDG&E, SCE
LEVEL OF SOLAR ANALYZED	15% of system peak load
STAKEHOLDER PERSPECTIVE	Total resource cost (TRC)
GRANULARITY OF ANALYSIS	• Solar characterization - Simulated hourly PV output for each configuration (horizontal, fixed tilt, tracking) for each substation based on 2010 weather • *Marginal resource/losses characterization - Energy: historical hourly day-ahead market price shapes (CAISO)*; Capacity: fixed cost of a new CT less net energy, AS revenues (see Overview box); Energy loss factors by TOU period, season; Capacity loss factors at peak periods • Geographic granularity - Compared hourly load at the individual substation level to potential PV generation at the same location at 1,800 substations
TOOLS USED	E3 Avoided Cost Calculator

Highlights

- *Local DPV is defined as PV sized such that its output will be consumed by load on the feeder or* substation where it is interconnected. Specifically, the generation cannot backflow from the distribution system onto the transmission system.
- The process for identifying sites included using GIS data to identify sites surrounding each of approximately 1,800 substations in PG&E, SDG&E and SCE. The study compared hourly load that the individual substation level to potential DPV generation at the same location.
- Cost of local distributed DPV increases significantly with Investment Tax Credit (ITC) expiration in 2017.
- When DPV is procured on a least net cost basis, opportunities may exist to locate in areas with high avoided costs. In 2012, a least net cost procurement approach results in net costs that are approximately $65 million lower assuming avoided transmission and distribution costs can be realized. These benefits carry through to 2016 for the most part, but disappear by 2020, when all potential has been realized regardless of cost.

OVERVIEW OF VALUE CATEGORIES



Energy: Estimate of hourly wholesale value of energy adjusted for losses between the point of wholesale transaction and delivery. Annual forecast based on market forwards that transition to annual average market price needed to cover the fixed and operating costs of a new CCGT, less net revenue from day-ahead energy, ancillary service, and capacity markets. Hourly forecast derived based on historical hourly day-ahead market price shapes from CAISO's MRTU system.

System Losses: Losses between the delivery location and the point of wholesale energy transaction. Losses scale with energy value, and reflect changing losses at peak periods.

Generation Capacity: In the long-run (after the resource balance year), generation capacity value is based on the fixed cost of a new CT less expected revenues from real-time energy and ancillary services markets. Prior to resource balance, value is based on a resource adequacy value.

T&D Capacity: Value is based on the "present worth" approach to calculate deferment value, incorporating investment plans as reported by utilities.

Grid Support Services (Ancillary Services): Value based on the value of avoided reserves, scaling with energy.

Carbon: Value of CO_2 emissions, based on an estimate of the marginal resource and a meta-analysis of forecasted carbon prices.

Solar Cost -The installed system cost, the cost of land and permitting, and the interconnection cost

*E3's components of electricity avoided costs include generation energy, line losses, system capacity, ancillary services, T&D capacity, environment.

STUDY CHARACTERISTICS	
STUDY OBJECTIVE	"To explore recent claims from California's investor-owner utilities that the state's NEM policy causes substantial cost shifts between energy customers with Solar PV systems and non-solar customers, particularly in the residential market."
GEOGRAPHIC FOCUS	California
SYSTEM CONTEXT	33% RPS, retail net metering, increasing solar penetration, ISO market
LEVEL OF SOLAR ANALYZED	Up to 5% of peak (by capacity)
STAKEHOLDER PERSPECTIVE	Ratepayers
GRANULARITY OF ANALYSIS	• Solar characterization - Used PVWatts to produce hourly PV outputs at representative locations • Marginal resource/losses characterization - Based on E3 avoided cost model (Sept 2011), which determines hourly energy market values and capacity based on CT (since resource balance year not used in this study) • Geographic granularity - Major climate zones for each IOU; costs from utility rate case filings used as proxy for long-run marginal cost T&D investment avoided
TOOLS USED	E3 Avoided Cost Calculator (2011), PVWatts

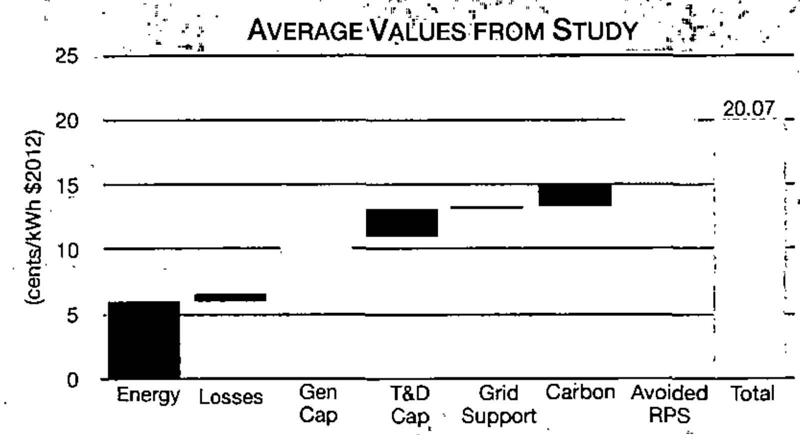
Highlights

- The study concludes that "on average over the residential markets of the state's three big IOUs, NEM does not impose costs on non-participating ratepayers, and instead creates a small net benefit." This conclusion is driven by "recent significant changes that the CPUC has adopted in IOUs' residential rate designs" plus "recognition that [DPV]...avoid other purchases or renewable power, resulting in a significant improvement in the economics of NEM compared to the CPUC's 2009 E3 NEM Study."

- The study focused on seven benefits: avoided energy, avoided generation capacity, reduced cost for ancillary services, lower line losses, reduced T&D investments, avoided RPS purchases, and avoided emissions. The study's analysis reflects costs to other customers (ratepayers) from "bill credits that the utility provides to solar customers as compensation for NEM exports, plus any incremental utility costs to meter and bill NEM customers." These costs are not quantified and levelized individually in the report, so they are not reflected in the chart to the right.

- The study bases its DPV value assessment on E3's avoided cost model and approach. It updates key assumptions including natural gas price forecast, greenhouse gas allowance prices, and ancillary services revenues, and excludes the resource balance year approach (the year in which avoided costs change from short-run to long-run). The study views the resource balance year as inconsistent with the modular, short lead-time nature of DPV. The study only considered the value of the exports to the grid under the utility's NEM program.

OVERVIEW OF VALUE CATEGORIES



Energy: Wholesale value of energy adjusted for losses between the point of the wholesale transaction and the point of delivery. Crossborder adjusted natural gas price forecast and greenhouse gas price forecast.

System Losses: The loss in energy from transmission and distribution across distance.

Generation Capacity: The cost of building new generation capacity to meet system peak loads. Crossborder does not use E3's "resource balance year" approach, which means that generation capacity value is based on long-run avoided capacity costs.

T&D Capacity: The costs of expanding transmission and distribution capacity to meet peak loads.

Grid Support Services (Ancillary Services): The marginal cost of providing system operations and reserves for electricity grid reliability. Crossborder updated assumed ancillary services revenues.

Carbon: The cost of carbon dioxide emissions associated with the marginal generating resource.

Avoided RPS: The avoided net cost of procuring renewable resources to meet an RPS Portfolio that is a percentage of total retail sales due to a reduction in retail loads.

VOTE SOLAR INITIATIVE, 2005

QUANTIFYING THE BENEFITS OF SOLAR POWER FOR CALIFORNIA

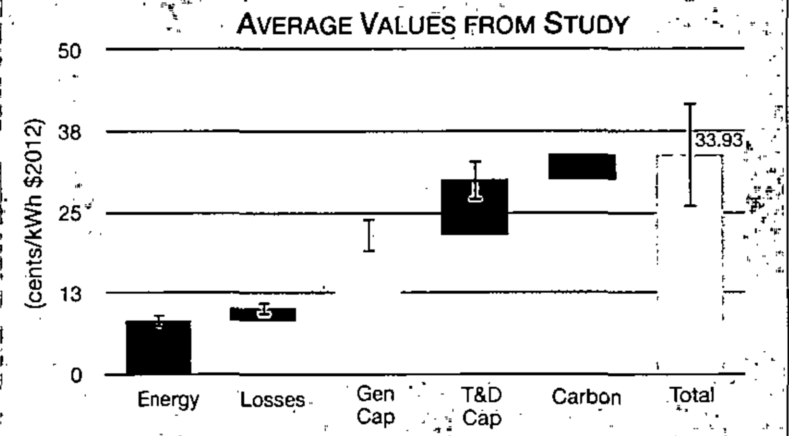
Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To provide a quantitative analysis of key benefits of solar energy for California.
GEOGRAPHIC FOCUS	California
SYSTEM CONTEXT	California's 3 investor-owned utilities (IOU): PG&E, SDG&E, SCE
LEVEL OF SOLAR ANALYZED	Unspecified
STAKEHOLDER PERSPECTIVE	Utility, ratepayer, participant, society
GRANULARITY OF ANALYSIS	• Solar characterization - Assumed average solar PV ELCC to be 50% from range of 36%-70% derived from NREL study[1] • Marginal resource/losses characterization - Assumed natural gas generation plant on margin both for peak demand and non-peak periods • Geographic granularity - Not considered in this study
TOOLS USED	Spreadsheet analysis

Highlights

- The study concluded that the value of on-peak solar energy in 2005 ranged from \$0.23 - 0.35 /kWh.
- The analysis looks at avoided costs under two alternative scenarios for the year 2005. The two scenarios vary the cost of developing new power plants and the price of natural gas.
  - Scenario 1 assumed new peaking generation will be built by the electric utility at a cost of capital of 9.5% with cost recovery over a 20 year period; the price of natural gas is based on the 2005 summer market price (average gas price)
  - Scenario 2 assumed new peaking generation will be built by a merchant power plant developer at a cost of capital of 15% with cost recovery over a 10 year period; the price of natural gas is based on the average gas price in California for the period of May 2000 through June 2001 (high gas price – 24% higher)
- While numerous unquantifiable benefits were noted, five benefits were quantified:
  1) Deferral of investments in new peaking power capacity
  2) Avoided purchase of natural gas used to produce electricity
  3) Avoided emissions of CO_2 and NO_x that impact global climate and local air quality
  4) Reduction in transmission and distribution system power losses
  5) Deferral of transmission and distribution investments that would be needed to meet growing loads.
- The study assumed that, "in California, natural gas is the fuel used by power plants on the margin both for peak demand periods and non-peak periods. Therefore it is reasonable to assume the solar electric facilities will displace the burning of natural gas in all hours that they produce electricity."

OVERVIEW OF VALUE CATEGORIES



Energy: Avoided fuel and variable O&M. Natural gas fuel price multiplied by assumed heat rate of peaking power plant (9360 MMBtu/kWh). Assumed value of consumables such as water and ammonia to be approximately 0.5 cents/kWh. For non-peak, average heat rates of existing fleet of natural gas plants were used for each electric utility's service area. Assumed heat rates: PG&E: 8740 MMBtu/kWh, SCE - 9690 MMBtu/kWh, SDG&E – 9720 MMbtu/kWh.

System Losses: Solar assumed to be delivered at secondary voltage. The summer peak and the summer shoulder loss factors are used to calculate the additional benefit derived from solar power systems because of their location at load.

Generation Capacity: Cost of installing a simple cycle gas turbine peaking plant multiplied by DPV's ELCC and a capital recovery factor, converted into costs per kilowatt hour by expected hours of on-peak operation.

T&D Capacity: One study area was selected for each utility to calculate the value of solar electricity in avoiding T&D upgrades. To simplify the analysis the need for T&D upgrades was assumed to be driven by growth in demand during 5% of the hours in a year. The 50% ELCC was used used in calculating the value of avoided T&D upgrades.

Carbon: Assumed to be the avoided air emissions, CO_2 and NOx, created from marginal generator (natural gas). CO_2 = \$100/ton; NOx = \$.014/kWh

1 "Solar Resource-Utility Load-Matching Assessment," Richard Perez, National Renewable Energy Laboratory, 1994

RICHARD DUKE, ENERGY POLICY, 2005

ACCELERATING RESIDENTIAL PV EXPANSION: DEMAND ANALYSIS FOR COMPETITIVE ELECTRICITY MARKETS

Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To quantify the potential market for grid-connected, residential PV electricity integrated into new houses built in the US.
GEOGRAPHIC FOCUS	California and Illinois
SYSTEM CONTEXT	California: 33% RPS, mostly gas generation; Illinois: mostly coal generation
LEVEL OF SOLAR ANALYZED	not stated; assumed low
STAKEHOLDER PERSPECTIVE	System
GRANULARITY OF ANALYSIS	• Solar characterization - Single estimated insolation for two states analyzed • Marginal resource/losses characterization - For energy, marginal resource is a natural gas plant in California and a cola plant in Illinois. For capacity, marginal resource is a gas turbine in both states. Losses based on average and peak loss factors estimated in secondary sources. • Geographic granularity - Transmission and distribution system impacts not accounted for since they are site specific
TOOLS USED	High level, largely based on secondary analysis

Highlights

- Total value varies significantly between the two regions studied largely driven by what the off-peak marginal resource is (gas vs coal). Coal has significantly higher air pollution costs, although lower fuel costs.
- The study notes that true value varies dramatically with local conditions, so precise calculations at a high-level analysis level are impossible. As such, transmission and distribution impacts were acknowledged but not included.

OVERVIEW OF VALUE CATEGORIES*

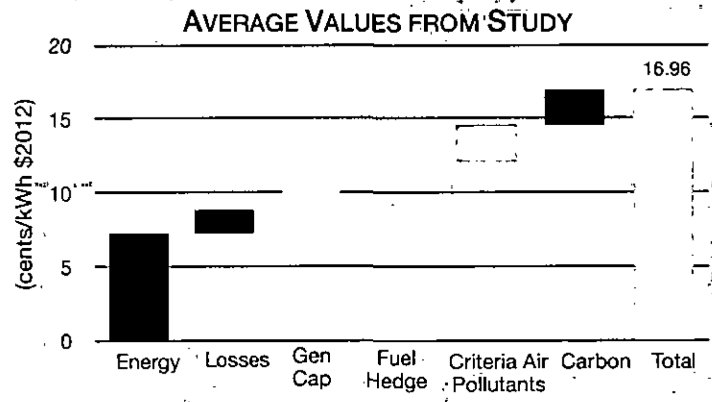


Chart data only reflects California assessment for comparison

Energy: Energy value is based on the marginal resource on-peak (gas combustion turbine) and off-peak (inefficient gas in California, and coal in Illinois). Fuel prices are based on Energy Information Administration projections, and levelized.

System Losses: Energy losses are assumed to be 7-8% off-peak, and up to twice that on-peak. Losses are only included as energy losses.

Generation Capacity: Generation capacity value is based on the assumption that the marginal resource is always a gas combustion turbine. Effective capacity is based on an ELCC estimate from secondary sources.

Fuel Price Hedge Value: Hedge value is estimated based on the market value to utilities of a fixed natural gas price for up to 10 years based on market swap data. The hedge is assumed to be additive since EIA gas prices were used rather than NYMEX futures market.

Criteria Air Pollutants: Criteria air pollutant reduction value is based on avoided costs of health impacts, estimated by secondary sources.

Carbon: Carbon value is the price of carbon (estimated based on European market projections) times the amount of carbon displaced.

LAWRENCE BERKELEY NATIONAL LAB, 2012

CHANGES IN THE ECONOMIC VALUE OF VARIABLE GENERATION AT HIGH PENETRATION LEVELS: A PILOT CASE STUDY OF CALIFORNIA

eLab
Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To quantify the change in value for a subset of economic benefits (energy, capacity, ancillary services, DA forecasting error) that results from using renewable generation technologies (wind, PV, CSP, & Thermal Energy Storage) at different penetration levels.
GEOGRAPHIC FOCUS	Loosely based on California
SYSTEM CONTEXT	33% RPS, ISO market
LEVEL OF SOLAR ANALYZED	Up to 40% (by energy)
STAKEHOLDER PERSPECTIVE	System
GRANULARITY OF ANALYSIS	• Solar characterization - Hourly satellite derived insolation data from National Solar Research Database, 10 km x 10 km granularity, NREL SAM model • Marginal resource/losses characterization - For energy and capacity, modeled hourly market prices, reflecting day-ahead, real-time, and ancillary services • Geographic granularity - Not considered in this study
TOOLS USED	Customized model that evaluates long-run investment decisions and short-term dispatch and operations

Highlights

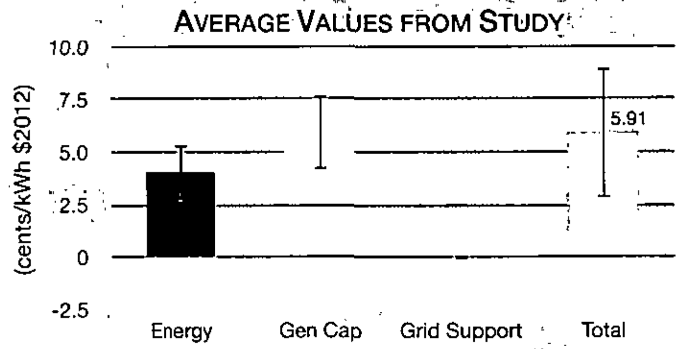
- The marginal economic value of solar exceeds the value of flat block power at low penetration levels, largely attributable to generation capacity value and solar coincidence with peak.

- The marginal value of DPV drops considerably as the penetration of solar increases, initially, driven by a decrease in capacity value with increasing solar generation. At the highest renewable penetrations considered, there is also a decrease in energy value as DPV displaces lower cost resources.

- The study notes that it is critical to use an analysis framework that addresses long-term investment decisions as well as short-term dispatch and operational constraints.

- Several costs and impacts are not considered in the study, including environmental impacts, transmission and distribution costs or benefits, effects related to the lumpiness and irreversibility of investment decisions, uncertainty in future fuel and investment capital costs, and DPV's capital cost.

OVERVIEW OF VALUE CATEGORIES



Energy: Energy value decreases at high penetrations because the marginal resource that DPV displaces changes as the system moves down the dispatch stack to a lower cost generator. Energy value is based on the short-run profit earned in non-scarcity hours (those hours where market prices are under $500/MWh), and generally displaces energy from a gas combined cycle. Fuel costs are based on Energy Information Administration projections.

Generation Capacity: Generation capacity value is based on the portion of short-run profit earned during hours with scarcity prices (those hours where market price equals or exceeds $500/MWh). Effective DPV capacity is based on an implied capacity credit as a result of the model's investment decisions, rather than a detailed reliability or ELCC analysis.

Grid Support (Ancillary Services): Ancillary services value is the net earnings from selling ancillary services in the market as well as paying for increased ancillary services due to increased short-term variability and uncertainty.

STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To quantify the cost and value components provided to utilities, ratepayers, and taxpayers by grid-connected, DPV in Pennsylvania and New Jersey.
GEOGRAPHIC FOCUS	7 cities across PA and NJ
SYSTEM CONTEXT	PJM ISO
LEVEL OF SOLAR ANALYZED	15% of system peak load, totaling 7 GW across the 7 utility hubs
STAKEHOLDER PERSPECTIVE	Utility, ratepayers, taxpayer
GRANULARITY OF ANALYSIS	• Solar characterization - Hourly estimates based on SolarAnywhere (satellite-derived irradiance data and simulation model with a 10 km x 10 km pixel resolution) • Marginal resource/losses characterization - For energy and capacity, marginal resource assumed to be CT; Marginal loss savings calculated, although methodology unclear • Geographic granularity - Locational marginal price node
TOOLS USED	Clean Power Research's Distributed PV Value Calculator; Solar Anywhere, 2012

Highlights

- The study evaluated 10 benefits and 1 cost. Evaluated benefits included: Fuel cost savings, O&M cost savings, security enhancement, long term societal benefit, fuel price hedge, generation capacity, T&D capacity, market price reduction, environmental benefit, economic development benefit. The cost evaluated was the solar penetration cost.

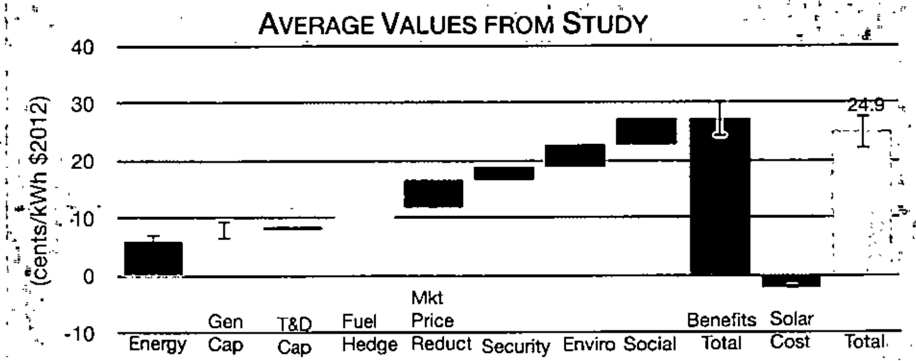
- The analysis represents the value of PV for a "fleet" of PV systems, evaluated in 4 orientations, each at 7 locations (Pittsburgh, PA; Harrisburg, PA; Scranton, PA; Philadelphia, PA; Jamesburg, NJ; Newark, NJ; and Atlantic City, NJ), spanning 6 utility service territories, each differing by: cost of capital, hourly loads, T&D loss factors, distribution expansion costs, and growth rate.

- The total value ranged from $256 to $318/MWh. Of this, the highest value components were the Market Price Reduction (avg $55/MWh) and Economic Development Value (avg $44/MWh).

- The moderate generation capacity value is driven by a moderate match between DPV output and utility system load. The effective capacity ranges from 28% to 45% of rated output (in line with the assigned PJM value of 38% for solar resources).

- Loss savings were not treated as a stand-alone benefit under the convention used in this methodology. Rather, the loss savings effect is included separately for each value component.

OVERVIEW OF VALUE CATEGORIES



Energy: Fuel and O&M cost savings. PV output plus loss savings times marginal energy cost, summed for all hrs of the year, discounted over PV life (30 years). Marginal energy costs are based on fuel and O&M costs of the generator most likely operating on the margin (assumed to be a combined cycle gas turbine). Assumed natural gas price forecast: NYMEX futures years 0-12; NYMEX futures price for year 12 x 2.33% escalation factor. Escalation rate assumed to be the same as the rate of wellhead price escalation from 1981-2011.

Generation Capacity: Capital cost of displace generation times PV's effective load carrying capability (ELCC), taking into account loss savings.

T&D Capacity: 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. In this study, T&D values were based on utility-wide average loads, which may obscure higher value areas.

Fuel Price Hedge Value: Cost to eliminate the fuel price uncertainty associated with natural gas generation through procurement of commodity futures. The value is directly related to the utility's cost of capital.

Market Price Reduction: Value to customers of the reduced cost of wholesale energy as a result of PV installation decreasing the demand for wholesale energy. Quantified through an analysis of the supply curve and reduction in demand, and the accompanying new market clearing price.

Security Enhancement Value: Annual cost of power outages in the U.S. times the percent (5%) that are high-demand stress type that can be effectively mitigated by DPV at a capacity penetration of 15%.

Social (Economic Development Value): Value of tax revenues associated with net job creation for solar vs conventional power generation. PV hard and soft cost /kW times portion of each attributed to local jobs, divided by annual PV system energy produced, minus CCGT cost/kW times portion attributed to local jobs divided by annual energy produced. Levelized over the 30 year lifetime of PV system, adjusted for lost utility jobs, multiplied by tax rate of a $75K salary, multiplied by indirect job multiplier.

Environmental: Environmental cost of a displaced conventional generation technology times the portion of this technology in the energy generation mix, repeated and summed for each conventional generation sources displaced by PV. Environmental cost for each generation source based on costs of GHG, SOx / NOx emissions, mining degradations, ground-water contamination, toxic releases and wastes. etc...as calculated in several environmental health studies.

THE VALUE OF DISTRIBUTED SOLAR ELECTRIC GENERATION TO SAN ANTONIO

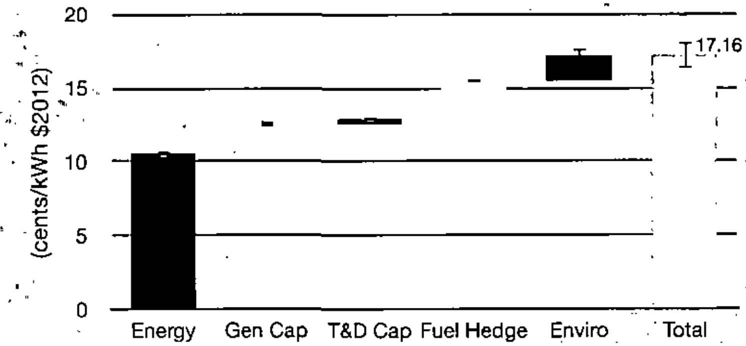
eLab Electricity Innovation Lab ROCKY MOUNTAIN INSTITUTE

STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To quantify the value provided by grid-connected, DPV in San Antonio from a utility perspective.
GEOGRAPHIC FOCUS	CPS Energy territory
SYSTEM CONTEXT	Municipal utility
LEVEL OF SOLAR ANALYZED	1.1-2.2% of peak load (by capacity)
STAKEHOLDER PERSPECTIVE	Utility
GRANULARITY OF ANALYSIS	• Solar characterization - Hourly estimates based on SolarAnywhere (satellite-derived irradiance data and simulation model with a 10 km x 10 km pixel resolution) to provide time- and location-correlated PV output with utility loads • Marginal resource/losses characterization - For energy and capacity, marginal resource assumed to be an "advanced gas turbine"; losses calculated on marginal basis • Geographic granularity - Not specified
TOOLS USED	Clean Power Research's SolarAnywhere, PVSimulator, DGValuator

Highlights

- The study concludes that DPV provides significant value to CPS Energy, primarily driven by energy, generation capacity deferment, and fuel price hedge value. The study is based solely on publicly-available data; it notes that results would be more representative with actual financial and operating data. Value is a levelized over 30 years.
- The study notes that value likely decreases with increasing penetration, although higher penetration levels needed to estimate this decrease were not analyzed.
- The study acknowledged but did not quantify a number of other values including climate change mitigation, environmental mitigation, and economic development.

OVERVIEW OF VALUE CATEGORIES



Energy: The study shows high energy value compared to other studies, driven by using EIA's "advanced gas turbine" with a high heat rate as the marginal resource. The natural gas price forecast is based on NYMEX forward market gas prices, then escalated at a constant rate. Energy losses are included in energy value, and are calculated on an hourly marginal basis.

Generation Capacity: Generation capacity value is DPV's effective capacity times the fixed costs of an "advanced gas turbine", assumed to be the marginal resource. Effective capacity based on ELCC; the reported ELCC is significantly higher than other studies. Every installed unit of DPV is given generation capacity value.

T&D Capacity: The study takes a two step approach: first, an economic screening to determine expansion plan costs and load growth expectations by geographic area, and second, an assessment of the correlation of DPV and load in the most promising locations.

Fuel Price Hedge: The study estimates hedge value as a combination of two financial instruments, risk-free zero-coupon bonds and a set of natural gas futures contracts, to represent the avoided cost of reducing fuel price volatility risk.

Environmental: The study quantified environmental value, as shown in the chart above, but did not include it in its final assessment of benefit since the study was from the utility perspective.

AUSTIN ENERGY & CLEAN POWER RESEARCH, 2006

THE VALUE OF DISTRIBUTED PHOTOVOLTAICS IN AUSTIN ENERGY AND THE CITY OF AUSTIN

Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

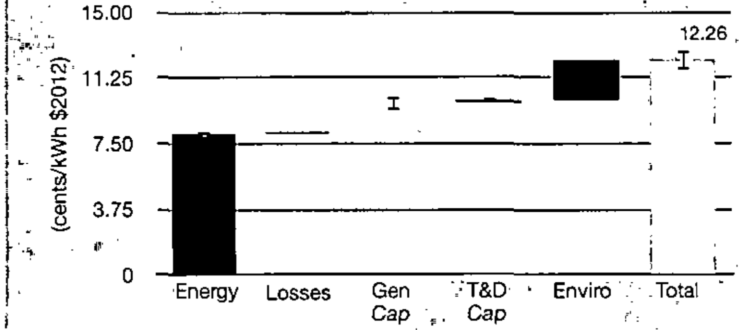
STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To quantify the comprehensive value of DPV to Austin Energy (AE) in 2006 and document methodologies to assist AE in performing analysis as conditions change and, to apply to other technologies
GEOGRAPHIC FOCUS	Austin, TX
SYSTEM CONTEXT	Municipal utility
LEVEL OF SOLAR ANALYZED	2%* system peak load
STAKEHOLDER PERSPECTIVE	Utility, ratepayer, participant, society
GRANULARITY OF ANALYSIS	• Solar characterization - Hourly PV output simulated for select PV configurations using irradiance data from hourly geostationary satellites; Validated using ground data from several climatically distinct locations including Austin, TX • *Marginal resource/losses characterization - Energy: based on internal marginal* energy cost provided by AE; • Geographic granularity - PV capacity value (ELCC) estimated system wide; Informed distribution avoided costs with area-specific distribution expansion plans "broken down by location and by the expenditure category"
TOOLS USED	Clean Power Research internal analysis; satellite solar data; PVFORM 4.0 for solar simulation; AE's load flow analysis for T&D losses

Highlights

- The study evaluated 7 benefits–energy production, line losses, generation capacity, T&D capacity, reactive power control (*grid support*), environment, natural gas price hedge (*financial*), and disaster recovery (*security*).
- The analysis assumed a 15 MW system in 7 PV system orientations, including 5 fixed and 2 single-axis.
- Avoided energy costs are the most significant source of value (about two-thirds of the total value), which is highly sensitive to the price of natural gas.
- Distribution capacity deferral value was relatively minimal. AE personnel estimated that 15% of the distribution capacity expansion plans have the potential to be deferred after the first ten years (assuming growth rates remain constant). Therefore, the study assumed that currently budgeted distribution projects were not deferrable, but the addition of PV could possibly defer distribution projects in the 11th year of the study period.
- Two studied values were excluded from the final results:
  - While reactive power benefits was estimated, the value ($0-$20/kW) was assumed not to justify the cost of the inverter that would be required to access the benefit (estimated cost not included).
  - The value of disaster recovery could be significant, but more work is needed before this value can be explicitly captured.

OVERVIEW OF VALUE CATEGORIES

AVERAGE VALUES FROM STUDY



Energy: PV output plus loss savings times marginal energy cost. Marginal energy costs are based on fuel and O&M costs of the generator most likely operating on the margin (typically, a combined cycle gas turbine).

System Losses: Computed differently depending upon benefit category. For all categories, loss savings are calculated hourly on the margin.

Generation Capacity: Cost of capacity times PV's effective load carrying capability (ELCC), taking into account loss savings.

Fuel price Hedge: Cost to eliminate the fuel price uncertainty associated with natural gas generation through procurement of commodity futures. Fuel price hedge value is included in the energy value.

T&D Capacity: 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.

Environmental: PV output times REC price—the incremental cost of offsetting a unit of conventional generation.

*ELCC was evaluated from 0%-20%; however, the ELCC estimate for 2% penetration was used in final value.

DESIGNING AUSTIN ENERGY'S SOLAR TARIFF USING A DISTRIBUTED PV CALCULATOR

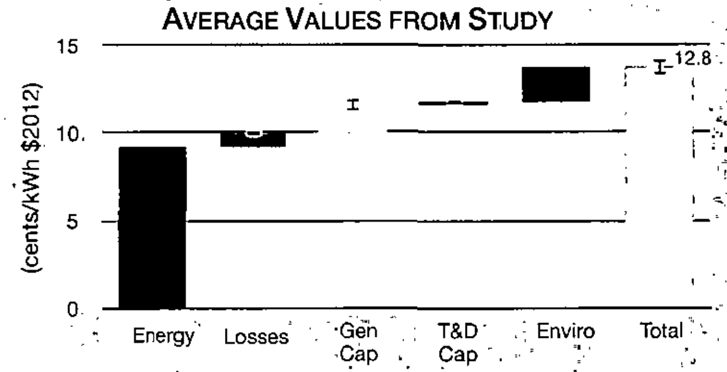
Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To design a residential solar tariff based on the value of solar energy generated from DPV systems to Austin Energy
GEOGRAPHIC FOCUS	Austin, TX
SYSTEM CONTEXT	Municipal utility with access to ISO (ERCOT)
LEVEL OF SOLAR ANALYZED	Assumed to be 2012 levels of penetration (5 MW)[1] < 0.5% penetration by energy[2]
STAKEHOLDER PERSPECTIVE	Utility
GRANULARITY OF ANALYSIS	Assumed to replicate granularity of AE/CPR 2006 study
TOOLS USED	Clean Power Research's Distributed PV Value Calculator; Solar Anywhere, 2012

Highlights

- The study focused on 6 benefits–energy, generation capacity, fuel price hedge value (included in energy savings), T&D capacity, and environmental benefits–which represent "a 'break-even' value...at which the utility is economically neutral to whether it supplies such a unit of energy or obtains it from the customer." The approach, which builds on the 2006 CPR study, is "an avoided cost calculation at heart, but improves on [an avoided cost calculation]... by calculating a unique, annually adjusted value for distributed solar energy."
- The fixed, south-facing PV system with a 30-degree tilt, the most common configuration and orientation in AE's service territory of approximately 1,500 DPV systems, was used as the reference system.
- As with the AE/CPR 2006 study, avoided energy costs are the most significant source of value, which is very sensitive to natural gas price assumptions.
- The levelized value of solar was calculated to total $12.8/kWh.
- Two separate calculation approaches were used to estimate the near term and long term value, combined to represent the "total benefits of DPV to Austin Energy" over the life time of a DPV system.
  - For the the near term (2 years) value of DPV energy, A PV output weighted nodal price was used to try to capture the relatively good correlation between PV output and electricity demand (and high price) that is not captured in the average nodal price.
  - To value the DPV energy produced during the mid and long term–through the rest of the 30-year assumed life of solar PV systems–the typical value calculator methodology was used.

OVERVIEW OF VALUE CATEGORIES



Energy: DPV output plus loss savings times marginal energy cost. Marginal energy costs are based on fuel and O&M costs of the generator most likely operating on the margin (typically, a combined cycle gas turbine).

System Losses: Computed differently depending upon benefit category. For all categories, loss savings are calculated hourly on the margin.

Generation Capacity: Cost of capacity times PV's effective load carrying capability (ELCC), taking into account loss savings.

Fuel Price Hedge Value: Cost to eliminate the fuel price uncertainty associated with natural gas generation through procurement of commodity futures. Fuel price hedge value is included in the energy value.

T&D Capacity: 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.

Environmental: PV output times Renewable Energy Credit (REC) price—the incremental cost of offsetting a unit of conventional generation.

Sources:
1) http://www.austinenergy.com/About%20Us/Newsroom/Reports/solarGoalsUpdate.pdf
2) http://www.austinenergy.com/About%20Us/Newsroom/Reports/2012AnnualPerformanceReportDRAFT.pdf

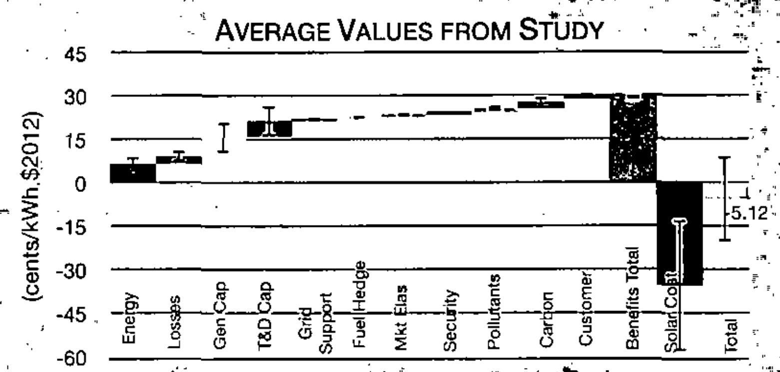
NAVIGANT CONSULTING FOR NREL, 2008
PHOTOVOLTAICS VALUE ANALYSIS

STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To summarize and describe the methodologies and range of values for the costs and values of 19 services provided or needed by DPV from existing studies.
GEOGRAPHIC FOCUS	Studies reviewed reflected varying geographies; case studies from TX, CA, MN, WI, MD, NY, MA, and WA
SYSTEM CONTEXT	n/a
LEVEL OF SOLAR ANALYZED	n/a
STAKEHOLDER PERSPECTIVE	Participating customers, utilities, ratepayers, society
GRANULARITY OF ANALYSIS	This study is a meta-analysis, so reflects a range of levels of granularity.
TOOLS USED	Custom-designed Excel tool to compare results and sensitivities

Highlights

- There are 19 key values of distributed PV, but the study concludes that only 6 have significant benefits (energy, generation capacity, T&D costs, GHG emissions, criteria air pollutant emissions, and implicit value of PV).
- Deployment location and solar output profile are the most significant drivers of DPV value.
- Several values require additional R&D to establish a standardized quantification methodology.
- Value can be proactively increased.

OVERVIEW OF VALUE CATEGORIES



Energy: Energy value is fuel cost times the heat rate plus O&M costs for the marginal power plant, generally assumed to be natural gas.

System Losses: Avoided loss value is the amount of loss associated with energy, generation capacity, T&D capacity, and environmental impact, times the cost of that loss.

Generation Capacity: Generation capacity value is the capital cost of the marginal power plant times the effective capacity (ELCC) of DPV.

T&D Capacity: T&D capacity value is T&D investment plan costs times the value of money times the effective capacity, divided by load growth, levelized.

Grid Support Services (Ancillary Services): Ancillary services include VAR support, load following, operating reserves, and dispatch and scheduling. DPV is unlikely to be able to provide all of these.

Financial (Fuel Price Hedge, Market Price Response): Hedge value is the cost to guarantee a portion of electricity costs are fixed. Reduced demand for electricity decreases the price of electricity for all customers and creates a customer surplus.

Security: Customer reliability in the form of increased outage support can be realized, but only when DPV is coupled with storage.

Environment (Criteria Air Pollutants, Carbon): Value is either the market value of penalties or costs, or the value of avoided health costs and shortened lifetimes. Carbon value is the emission intensity of the marginal resource times the value of emissions.

Customer: Value to customer of having green option, as indicate by their willingness to pay.

Solar cost: Costs include capital cost of equipment plus fixed operating and maintenance costs.

SOURCES

05

STUDIES REVIEWED IN ANALYSIS

eLab Electricity Innovation Lab ROCKY MOUNTAIN INSTITUTE

Study	Funded / Commissioned by	Prepared by
Xcel Energy, Inc. Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System. May 2013.	Xcel Energy	Xcel Energy
SAIC. 2013 Updated Solar PV Value Report. Arizona Public Service. May, 2013.	Arizona Public Service	SAIC (company that took over R.W. Beck)
Beach, R., McGuire, P., The Benefits and Costs of Solar Distributed Generation for Arizona Public Service. Crossborder Energy May, 2013.		Crossborder Energy
Norris, B., Jones, N. *The Value of Distributed Solar Electric Generation to San Antonio.* Clean Power Research & Solar San Antonio, March 2013.	DOE Sunshot Initiative	Clean Power Research & Solar San Antonio
Beach, R., McGuire, P., *Evaluating the Benefits and Costs of Net Energy Metering for Residential Customers in California.* Crossborder Energy, Jan. 2013.	Vote Solar Initiative	Crossborder Energy
Rabago, K., Norris, B., Hoff, T., *Designing Austin Energy's Solar Tariff Using A Distributed PV Calculator.* Clean Power Research & Austin Energy, 2012.	Austin Energy	Clean Power Research & Solar San Antonio
Perez, R., Norris, B., Hoff, T., *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania.* Clean Power Research, 2012.	The Mid-Atlantic Solar Energy Industries Association, & The Pennsylvania Solar Energy Industries Association	Clean Power Research
Mills, A., Wiser, R., *Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California.* Lawrence Berkeley National Laboratory, June 2012.	DOE Office of Energy Efficiency and Renewable Energy and Office of Electricity Delivery and Energy Reliability	Lawrence Berkeley National Laboratory
Energy and Environmental Economics, Inc. Technical Potential for Local Distributed Photovoltaics in California, Preliminary Assessment. March 2012.	California Public Utilities Commission	Energy and Environmental Economics, Inc. (E3)
Energy and Environmental Economics, Inc.California Solar Initiative Cost-Effectiveness Evaluation. April 2011.	California Public Utilities Commission	Energy and Environmental Economics, Inc. (E3)
R.W. Beck, Arizona Public Service, *Distributed Renewable Energy Operating Impacts and Valuation Study.* Jan. 2009.	Arizona Public Service	R.W. Beck, Inc with Energized Solutions, LLC, Phasor Energy Company, Inc, & Summit Blue Consulting, LLC
Perez, R., Hoff, T., Energy and Capacity Valuation of Photovoltaic Power Generation in New York. Clean Power Research, March 2008.	Solar Alliance and the New York Solar Energy Industry Association	
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Smeloff, E., *Quantifying the Benefits of Solar Power for California.* Vote Solar, Jan. 2005.	Vote Solar Initiative	Ed Smeloff
Duke, R., Williams, R., Payne A., *Accelerating Residential PV Expansion: Demand Analysis for Competitive Electricity Markets.* Energy Policy 33, 2005. pp. 1912-1929.	EPA STAR Fellowship, the Energy Foundation, The Packard Foundation, NSF	Princeton Environmental Institute, Princeton University

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Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

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ACRONYMS

AE - Austin Energy
APS - Arizona Public Service
AS - Ancillary Services
CCGT - Combined Cycle Gas Turbine
CHP - Combined Heat and Power
CPR - Clean Power Research
CT - Combustion Turbine
DER - Distributed Energy Resource
DPV - Distributed Photovoltaics
E3 - Energy + Environmental Economics
eLab - Electricity Innovation Lab
ELCC - Effective Load Carrying Capacity
FERC - Federal Energy Regulatory Commission
ISO - Independent System Operator
LBNL - Lawrence Berkeley National Laboratory
NREL - National Renewable Energy Laboratory
NYMEX - New York Mercantile Exchange
PV - Photovoltaic
RMI - Rocky Mountain Institute
SDG&E - San Diego Gas & Electric
SEPA - Solar Electric Power Association
SMUD - Sacramento Municipal Utility District
T&D - Transmission & Distribution
TOU - Time of Use

E-100 Sub136

Value of Solar to New Jersey and Pennsylvania

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Executive Summary

This report presents an analysis of value provided by grid-connected, distributed PV in Pennsylvania and New Jersey. The analysis does not provide policy recommendations except to suggest that each benefit must be understood from the perspective of the beneficiary (utility, ratepayer, or taxpayer).

The study quantified ten value components and one cost component, summarized in Table ES- 1. These components represent the benefits (and costs) that accrue to the utilities, ratepayers, and taxpayers in accepting solar onto the grid. The methodologies for quantifying these values are described further in Appendix 2.

Table ES- 1. *Value component definitions.*

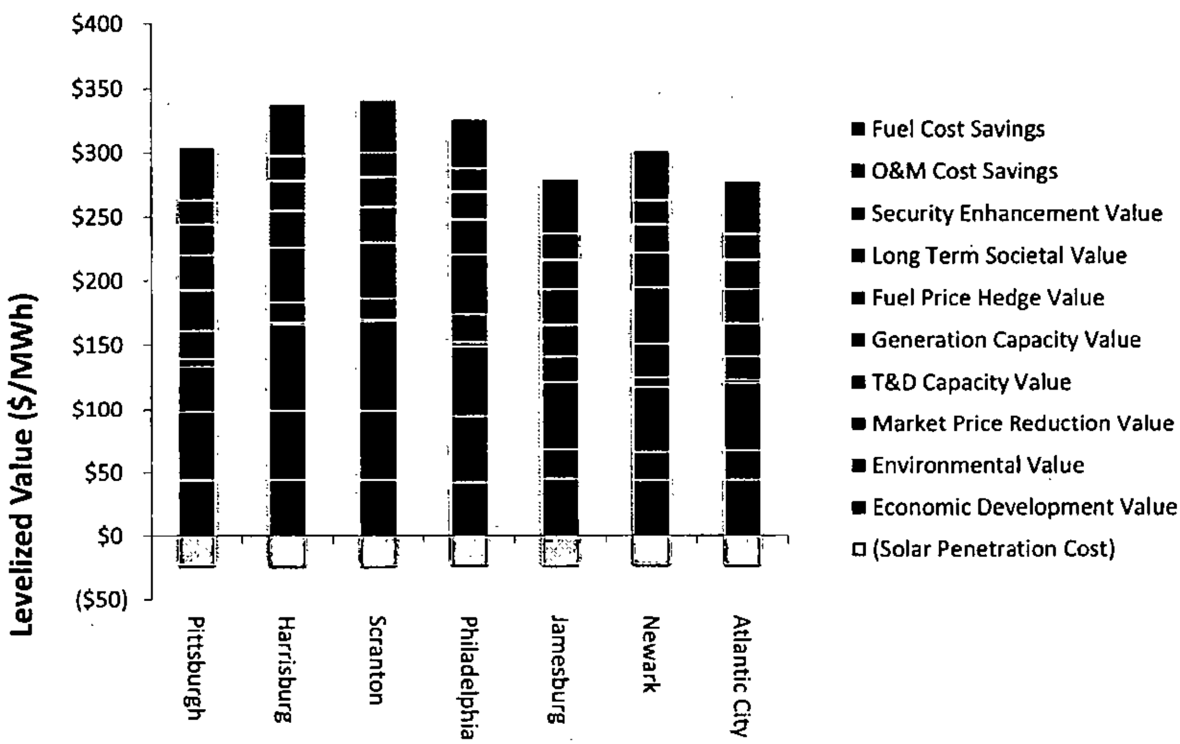
Value Component	Basis
Fuel Cost Savings	Cost of natural gas fuel that would have to be purchased for a gas turbine (CCGT) plant operating on the margin to meet electric loads and T&D losses.
O&M Cost Savings	Operations and maintenance costs for the CCGT plant.
Security Enhancement Value	Avoided economic impacts of outages associated due to grid reliability of distributed generation.
Long Term Societal Value	Potential value (defined by all other components) if the life of PV is 40 years instead of the assumed 30 years.
Fuel Price Hedge Value	Cost to eliminate natural gas fuel price uncertainty.
Generation Capacity Value	Cost to build CCGT generation capacity.
T&D Capacity Value	Financial savings resulting from deferring T&D capacity additions.
Market Price Reduction	Wholesale market costs incurred by all ratepayers associated with a shift in demand.
Environmental Value	Future cost of mitigating environmental impacts of coal, natural gas, nuclear, and other generation.
Economic Development Value	Enhanced tax revenues associated with net job creation for solar versus conventional power generation.
(Solar Penetration Cost)	Additional cost incurred to accept variable solar generation onto the grid.

The analysis represents the value of PV for a "fleet" of PV systems (that is, a large set of systems generating into the grid). Four different fleet configurations (e.g., fixed, south-facing, 30-degree tilt angle) were evaluated at each of seven locations. These locations represent a diversity of geographic and economic assumptions across six utility service territories.

The analysis represented a moderate assumption of penetration: PV was to provide 15% of peak electric load for each study location (higher penetration levels result in lower value). PV was modeled using SolarAnywhere®, a solar resource data set that provides time- and location-correlated PV output with loads. Load data and market pricing was taken from PJM for the six zones, and utility economic inputs were derived from FERC submittals. Additional input data was taken from the EIA and the Bureau of Labor Statistics (producer price indices).

Levelized value results for the seven locations are shown in Figure ES- 1 and Table ES- 2. Detailed results for all scenarios are included in Appendix 3.

Figure ES- 1. Levelized value ($/MWh), by location (South-30).



The following observations and conclusions may be made:

- **Total Value**. The total value ranges from $256 per MWh to $318 per MWh. Of this, the highest value components are the Market Price Reduction (averaging $55 per MWh) and the Economic Development Value (averaging $44 per MWh).
- **Market Price Reduction**. The two locations of highest total value (Harrisburg and Scranton) are noted for their high Market Price Reduction value. This may be the result of a good match between LMP and PV output. By reducing demand during the high priced hours, a cost savings is realized by all consumers. Further investigation of the methods may be warranted in light of two arguments put forth by Felder [32]: that the methodology does address induced increase in demand due to price reductions, and that it only addresses short-run effects (ignoring the impact on capacity markets).
- **Environmental Value**. The state energy mix is a differentiator of environmental value. Pennsylvania (with a large component of coal-fired generation in its mix) leads to higher environmental value in locations in that state relative to New Jersey.
- **T&D Capacity Value**. T&D capacity value is low for all scenarios, with the average value of only $3 per MWh. This may be explained by the conservative method taken for calculating the effective T&D capacity.
- **Fuel Price Hedge**. The cost of eliminating future fuel purchases—through the use of financial hedging instruments—is directly related to the utility's cost of capital. This may be seen by comparing the hedge value in Jamesburg and Atlantic City. At a rate of 5.68%, Jersey Central Power & Light (the utility serving Jamesburg) has the lowest calculated cost of capital among the six utilities included in the study. In contrast, PSE&G (the utility serving Newark) has a calculated discount rate of 8.46%, the highest among the utilities. This is reflected in the relative hedge values of $24 per MWh for Jamesburg and $44 per MWh for Newark, nearly twice the value.
- **Generation Capacity Value**. There is a moderate match between PV output and utility system load. The effective capacity ranges from 28% to 45% of rated output, and this is in line with the assigned PJM value of 38% for solar resources.

Table ES- 2. Levelized Value of Solar ($/MWh), by Location.

	Pittsburgh	Harrisburg	Scranton	Philadelphia	Jamesburg	Newark	Atlantic City
Energy							
Fuel Cost Savings	$41	$41	$41	$38	$42	$39	$41
O&M Cost Savings	$20	$20	$20	$18	$21	$19	$20
Total Energy Value	$61	$60	$60	$56	$63	$58	$61
Strategic							
Security Enhancement Value	$23	$23	$23	$22	$23	$22	$22
Long Term Societal Value	$28	$29	$29	$27	$28	$28	$28
Total Strategic Value	$51	$52	$52	$49	$51	$50	$50
Other							
Fuel Price Hedge Value	$31	$42	$42	$47	$24	$44	$25
Generation Capacity Value	$22	$16	$17	$22	$19	$26	$18
T&D Capacity Value	$6	$1	$1	$3	$1	$8	$2
Market Price Reduction Value	$35	$67	$69	$54	$52	$51	$54
Environmental Value	$54	$55	$55	$52	$23	$22	$23
Economic Development Value	$44	$45	$45	$42	$45	$44	$45
(Solar Penetration Cost)	($23)	($23)	($23)	($22)	($23)	($22)	($22)
Total Other Value	$170	$203	$206	$199	$143	$173	$144
Total Value	**$282**	**$315**	**$318**	**$304**	**$257**	**$280**	**$256**

Contents

Introduction: The Value of PV

This report attempts to quantify the value of distributed solar electricity in Pennsylvania and New Jersey. It uses methodologies and analytical tools that have been developed over several years. The framework supposes that PV is located in the distribution system. PV that is located close to the loads provides the highest value per unit of energy to the utility because line losses are avoided, thereby increasing the value of solar relative to centrally-located resources.

The value of PV may be considered the aggregate of several components, each estimated separately, described below. The methods used to calculate value are described in more detail in the Appendices.

Fuel Cost Savings

Distributed PV generation offsets the cost of power generation. Each kWh generated by PV results in one less unit of energy that the utility needs to purchase or generate. In addition, distributed PV reduces system losses so that the cost of the wholesale generation that would have been lost must also be considered.

Under this study, the value is defined as the cost of natural gas fuel that would otherwise have to be purchased to operate a gas turbine (CCGT) plant and meet electric loads and T&D losses. The study presumes that the energy delivered by PV displaces energy at this plant.

Whether the utility receives the fuel cost savings directly by avoiding fuel purchases, or indirectly by avowing wholesale power purchases, the method of calculating the value is the same.

O&M Cost Savings

Under the same mechanism described for Fuel Cost Savings, the utility realizes a savings in O&M costs due to decreased use of the CCGT plant. The cost savings are assumed to be proportional to the energy avoided, including loss savings.

Security Enhancement Value

The delivery of distributed PV energy correlated with load results in an improvement in overall system reliability. By reducing the risk of power outages and rolling blackouts, economic losses are reduced.

Long Term Societal Value

The study period is taken as 30 years (the nominal life of PV systems), and the calculation of value components includes the benefits provided over this study period. However, it is possible that the life can be longer than 30 years, in which case the full value would not be accounted for. This "long term societal value" is the potential extended benefit of all value components over a 10 year period beyond the study period. In other words, if the assumed life were 40 years instead of 30, the increase in total value is the long term societal value.

Fuel Price Hedge Value

PV generation is insensitive to the volatility of natural gas or other fuel prices, and therefore provides a hedge against price fluctuation. This is quantified by calculating the cost of a risk mitigation investment that would provide price certainty for future fuel purchases.

Generation Capacity Value

In addition to the fuel and O&M cost savings, the total cost of power generation includes capital cost. To the extent that PV displaces the need for generation capacity, it would be valued as the capital cost of displaced generation. The key to valuing this component is to determine the effective load carrying capability (ELCC) of the PV fleet, and this is accomplished through an analysis of hourly PV output relative to overall utility load.

T&D Capacity Value

In addition to capital cost savings for generation, PV potentially provides utilities with capital cost savings on T&D infrastructure. In this case, PV is not assumed to displace capital costs but rather defer the need. This is because local loads continue to grow and eventually necessitate the T&D capital investment. Therefore, the cost savings realized by distributed PV is merely the cost of capital saved in the intervening period between PV installation and the time at which loads again reach the level of effective PV capacity.

Market Price Reduction

PV generation reduces the amount of load on the utility systems, and therefor reduces the amount of energy purchased on the wholesale market. The demand curve shifts to the left, and the market clearing price is reduced. Thus, the presence of PV not only displaces the need for energy, but also reduces the cost of wholesale energy to all consumers. This value is quantified through an analysis of the supply curve and the reduction in demand.

Environmental Value

One of the primary motives for PV and other renewable energy sources is to reduce the environmental impact of power generation. Environmental benefits covered in this analysis represent future savings for mitigating environmental damage (sulfur dioxide emissions, water contamination, soil erosion, etc.).

Economic Development Value

Distributed PV provides local jobs (e.g., installers) at higher rates than conventional generation. These jobs, in turn, translate to tax revenue benefits to all taxpayers.

Solar Penetration Cost

In addition to the value provided by PV, there are costs that must be factored in as necessary to accept variable solar generation onto the grid. Infrastructural and operational expenses will be incurred to manage the flow of non-dispatchable PV resources. These costs are included as a negative value.

Value Perspective

The value of solar accrues either to the electric utility or to society (ratepayers and taxpayers), depending upon component. For example, PV reduces the amount of wholesale energy needed to serve load, resulting in savings to the utility. On the other hand, environmental mitication costs accrue to society.

Approach

Locations

Seven locations were selected to provide broad geographical and utility coverage in the two states of interest (see Table 1). Four locations were selected in Pennsylvania representing three utilities[1] and three locations were selected in New Jersey, each served by a separate utility.

Table 1. Study location summary.

		Location	Utility	2011 Utility Peak Load (MW)	PV Fleet Capacity (MW)
PA	1	Pittsburgh	Duquesne Light Co.	3,164	475
PA	2	Scranton	PPL Utilities Corp.	7,527	1,129
PA	3	Harrisburg	PPL Utilities Corp.	7,527	1,129
PA	4	Philadelphia	PECO Energy Co.	8,984	1,348
NJ	5	Jamesburg	Jersey Central P&L	6,604	991
NJ	6	Newark	PSE&G	10,933	1,640
NJ	7	Atlantic City	Atlantic City Electric	2,956	443

These locations represent a diversity of input assumptions:

- The locations span two states: PA and NJ. These states differ in generation mix (percentage of coal, gas, nuclear, etc.), and this is reflected in different environmental cost assumptions (see Appendix 2).
- The locations differ in solar resource.

[1] Scranton and Harrisburg are both served by PPL Utilities.

- The locations represent six different utility service territories. Each of these utilities differ by cost of capital, hourly loads, T&D loss factors, distribution expansion costs, and growth rate.

Penetration Level

Fleet capacity was set to 15% of the utility peak load. This assumption was intended to represent a moderate long-term penetration level.

The value of solar decreases with increasing penetration for several reasons:

- The match between PV output and loads is reduced. As more PV is added to the resource mix, the peak shifts to non-solar hours, thereby limiting the ability of PV to support the peak.
- Line losses are related to the square of the load. Consequently, the greatest marginal savings provided by PV is achieved with small amounts of PV. By adding larger and larger quantities of PV, the loss savings continue to be gained, but at decreasing rates.
- Similarly, the market prices are non-linear, and PV is most effective in causing market price reduction with small PV capacity.

Based on the above considerations, this study is intended to represent a moderate level of long-term PV penetration. With penetration levels less than 15%, the value of solar would be expected to be higher than the results obtained in this study.

Peak loads for each utility were obtained from hourly load data corresponding to PJM load zones, and these were used to set the fleet capacity as shown in the table.

Fleet Configurations

Four PV system configurations were included in the study:

- South-30 (south-facing, 30-degree tilt, fixed)
- Horizontal (fixed)
- West-30 (west facing, 30-degree tilt, fixed)
- 1-Axis (tracking at 30-degree tilt)

These were selected in order to capture possible variations in value due to the different production profiles. For example, West-facing systems are sometimes found to be the best match with utility loads and have the potential to provide more capacity benefits. On the other hand, tracking systems deliver more energy per unit of rated output, so they have the potential to offer more energy benefits (e.g., fuel cost savings).

Scenarios and Fleet Modeling

Value was determined for each of 28 scenarios (four fleet configurations at each of seven locations). For modeling purposes, fleets were described by latitude and longitude coordinates, AC rating, a module derate factor (90%), inverter efficiency (95%) and other loss factor (90%). These factors were consistent across all scenarios.

Fleets were modeled for all hours of 2011 using SolarAnywhere® satellite-derived irradiance data and simulation model with a 10 km x 10 km pixel resolution. [2] Under this procedure, the fleet output for each scenario is location- and time-correlated with hourly PJM zonal loads.

[2] http://www.solaranywhere.com.

Results

Utility Analysis

Utility analysis results are shown in Table 2, obtained from an analysis of FERC filings and PJM hourly data using methods developed previously for NYSERDA.[3] These include:

- Utility discount rate
- Utility system loss data
- Distribution expansion costs (present value)
- Distribution load growth rate
- Distribution loss data

Note that actual utility costs are used in this analysis because they are the basis of value. For this reason, the utility cost of capital is required (e.g., an "assumed" or "common" value cannot be used). The results may therefore differ, in part, due to differences in utility discount rate.

PV Technical Analysis

A summary of fleet technical performance results is presented in Table 3. Annual energy production is the modeled output for 2011. Capacity factor is the annual energy production relative to a baseload plant operating at 100% availability with the same rated output. Generation capacity is Effective Load Carrying Capability (ELCC) expressed as a percentage of rated capacity. T&D Capacity is a measure of the direct annual peak-load reduction provided by the PV system expressed as a percentage of rated capacity.

[3] Norris and Hoff, "PV Valuation Tool," Final Report (DRAFT), NYSERDA, May 2012.

Table 2. Utility analysis results.

		Pittsburgh	Scranton	Harrisburg	Philadelphia	Jamesburg	Newark	Atlantic City
Utility		Duquesne Light Co.	PPL Utilities Corp.	PPL Utilities Corp.	PECO Energy Co.	Jersey Central P&L	PSE&G	Atlantic City Electric
UtilityID		DUQ	PPL	PPL	PECO	JCPL	PSEG	AECO
UTILITY DATA								
Economic Factors								
Discount Rate	percent per year	6.63%	8.08%	8.08%	9.00%	5.68%	8.46%	5.88%
Utility System								
Load Loss Condition	MW	1,757	4,786	4,786	4,958	2,893	5,435	1,369
Avg. Losses (at Condition)	percent	5.84%	6.55%	6.55%	4.23%	6.35%	4.86%	5.61%
Distribution								
Distribution Expansion Cost	$ PW	$485,009,880	$423,994,174	$423,994,174	$722,046,118	$446,914,440	$573,820,751	$288,330,547
Distribution Expansion Cost Escalation	percent per year	3.89%	3.89%	3.89%	3.89%	3.89%	3.89%	3.89%
Distribution Load Growth Rate	MW per year	30.9	98.3	98.3	110.7	93.4	91.4	39.5
Load Loss Condition	MW	1,757	4,786	4,786	4,958	2,893	5,435	1,369
Avg. Losses (at Condition)	percent	5.84%	6.55%	6.55%	4.23%	6.35%	4.86%	5.61%

Table 3. Technical results, by location (South-30).

	Pittsburgh	Harrisburg	Scranton	Philadelphia	Jamesburg	Newark	Atlantic City
Fleet Capacity (MWac)	475	1129	1129	1348	991	1640	443
Annual Energy Production (MWh)	716,621	1,809,443	1,698,897	2,339,424	1,675,189	2,677,626	827,924
Capacity Factor (%)	17%	18%	17%	20%	19%	19%	21%
Generation Capacity (% of Fleet Capacity)	41%	28%	28%	38%	45%	45%	46%
T&D Capacity (% of Fleet Capaccity)	31%	14%	14%	21%	29%	56%	36%

Value Analysis

Figure 1 shows the value results in levelized dollars per MWh generated. Figure 2 shows the data in dollars per kW installed. This data is also presented in tabular form in Table 4 and Table 5. Detailed results for individual locations are shown in Appendix 3.

The total value ranges from \$256 per MWh to \$318 per MWh. Of this, the highest value components are the Market Price Reduction *(averaging \$55 per MWh) and the Economic Development Value (averaging* \$44 per MWh).

The differences between Table 4 and Table 5 are due to differences in the cost of capital between the utilities. For example, Atlantic City has the highest value per installed kW, but Atlantic City Electric has one of the lowest calculated discount rates (Table 2). Therefore, when this value is levelized over the 30 year study period, it represents a relatively low value.

Other observations:

- **Market Price Reduction.** The two locations of highest total value (Harrisburg and Scranton) are noted for their high Market Price Reduction value. This may be the result of a good match between LMP and PV output. By reducing demand during the high priced hours, a cost savings is realized by all consumers. Further investigation of the methods may be warranted in light of two arguments put forth by Felder [32]: that the methodology does address induced increase in demand due to price reductions, and that it only addresses short-run effects (ignoring the impact on capacity markets).
- **Environmental Value.** The state energy mix is a differentiator of environmental value. Pennsylvania (with a large component of coal-fired generation in its mix) leads to higher environmental value in locations in that state relative to New Jersey. As described in Appendix 2, the PA generation mix is dominated by coal (48%) compared to NJ (10%).
- **T&D Capacity Value.** T&D capacity value is low for all scenarios, with the average value of only \$3 per MWh. This may be explained by the conservative method taken for calculating the effective T&D capacity.
- **Fuel Price Hedge.** The cost of eliminating future fuel purchases—through the use of financial hedging instruments—is directly related to the utility's cost of capital. This may be seen by comparing the hedge value in Jamesburg and Atlantic City. At a rate of 5.68%, Jersey Central Power & Light (the utility serving Jamesburg) has the lowest calculated cost of capital among the

six utilities included in the study. In contrast, PSE&G (the utility serving Newark) has a calculated discount rate of 8.46%, the highest among the utilities. This is reflected in the relative hedge values of $24 per MWh for Jamesburg and $44 per MWh for Newark, nearly twice the value.

Figure 1. Levelized value ($/MWh), by location (South-30).

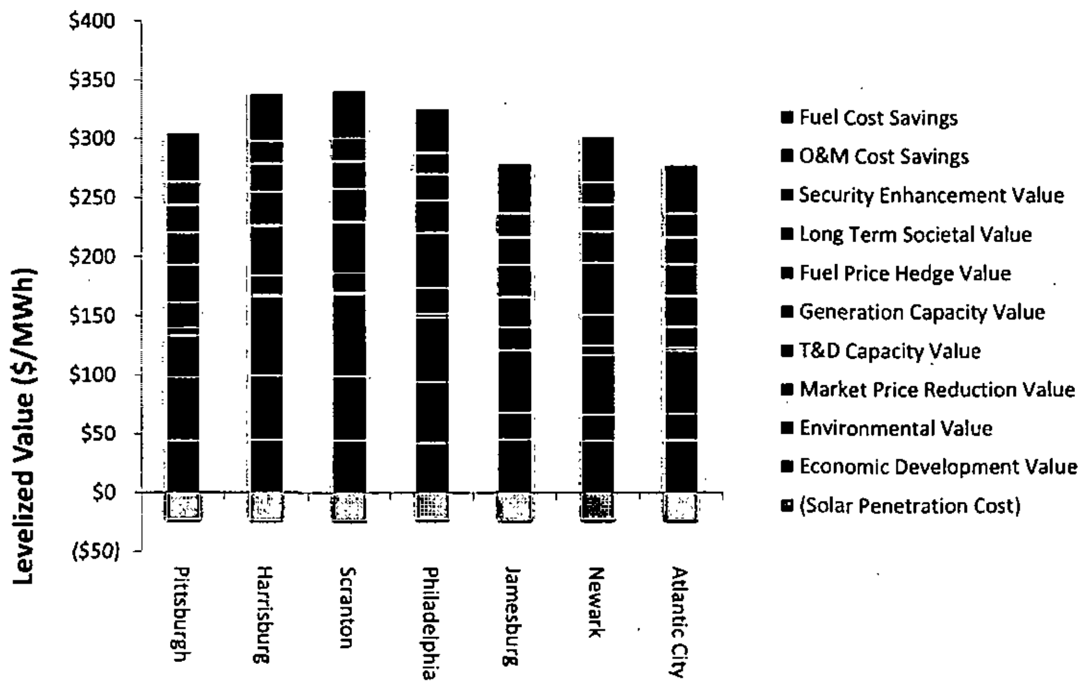


Figure 2. Value ($/kW), by location (South-30).

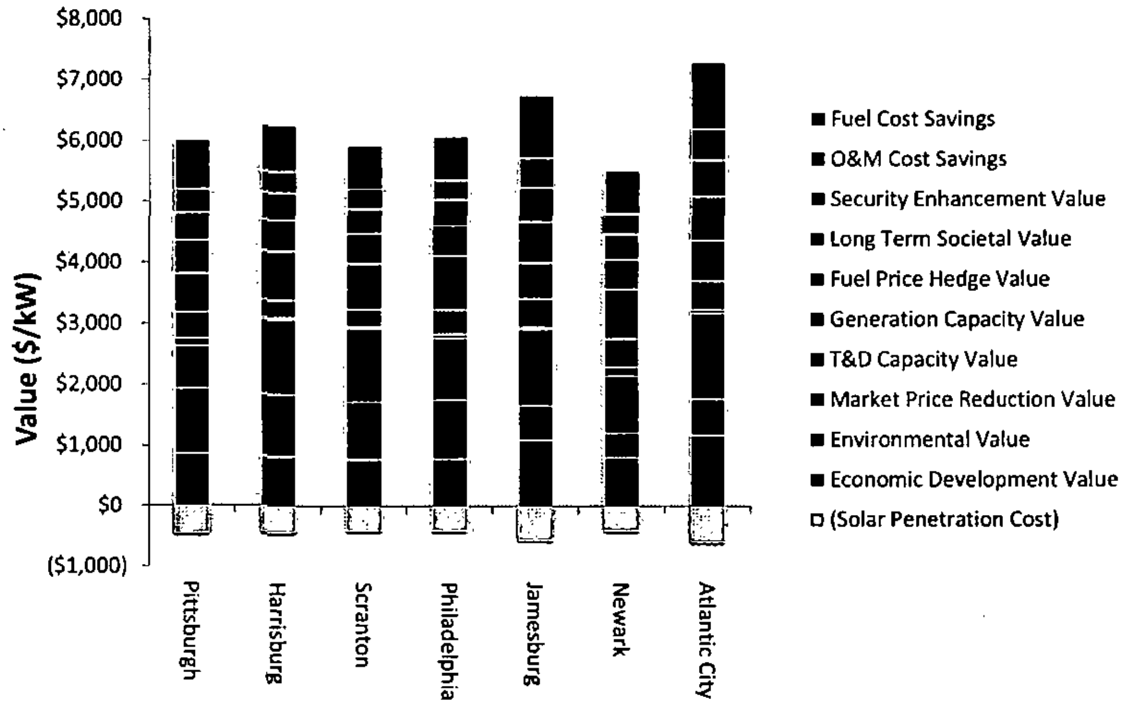


Table 4. Value (levelized $/MWh), by location (South-30).

	Pittsburgh	Harrisburg	Scranton	Philadelphia	Jamesburg	Newark	Atlantic City
Energy							
Fuel Cost Savings	$41	$41	$41	$38	$42	$39	$41
O&M Cost Savings	$20	$20	$20	$18	$21	$19	$20
Total Energy Value	$61	$60	$60	$56	$63	$58	$61
Strategic							
Security Enhancement Value	$23	$23	$23	$22	$23	$22	$22
Long Term Societal Value	$28	$29	$29	$27	$28	$28	$28
Total Strategic Value	$51	$52	$52	$49	$51	$50	$50
Other							
Fuel Price Hedge Value	$31	$42	$42	$47	$24	$44	$25
Generation Capacity Value	$22	$16	$17	$22	$19	$26	$18
T&D Capacity Value	$6	$1	$1	$3	$1	$8	$2
Market Price Reduction Value	$35	$67	$69	$54	$52	$51	$54
Environmental Value	$54	$55	$55	$52	$23	$22	$23
Economic Development Value	$44	$45	$45	$42	$45	$44	$45
(Solar Penetration Cost)	($23)	($23)	($23)	($22)	($23)	($22)	($22)
Total Other Value	$170	$203	$206	$199	$143	$173	$144
Total Value	**$282**	**$315**	**$318**	**$304**	**$257**	**$280**	**$256**

Table 5. Value ($/kW), by location (South-30).

	Pittsburgh	Harrisburg	Scranton	Philadelphia	Jamesburg	Newark	Atlantic City
Energy							
Fuel Cost Savings	$813	$751	$706	$706	$1,020	$709	$1,081
O&M Cost Savings	$396	$366	$344	$344	$497	$345	$527
Total Energy Value	$1,209	$1,117	$1,050	$1,049	$1,517	$1,054	$1,609
Strategic							
Security Enhancement Value	$446	$424	$398	$405	$549	$403	$584
Long Term Societal Value	$557	$530	$498	$507	$686	$504	$730
Total Strategic Value	$1,003	$954	$896	$912	$1,234	$907	$1,314
Other							
Fuel Price Hedge Value	*$613*	*$786*	*$738*	*$876*	*$586*	*$798*	*$662*
Generation Capacity Value	$432	$297	$290	$401	$468	$470	$478
T&D Capacity Value	$127	$24	$24	$65	$23	$147	$49
Market Price Reduction Value	$696	$1,241	$1,206	$1,013	$1,266	$927	$1,412
Environmental Value	$1,064	$1,011	$950	$967	$560	$411	$596
Economic Development Value	$870	$827	$777	$790	$1,097	$806	$1,168
(Solar Penetration Cost)	($446)	($424)	($398)	($405)	($549)	($403)	($584)
Total Other Value	$3,355	$3,761	$3,586	$3,706	$3,451	$3,156	$3,781
Total Value	**$5,568**	**$5,832**	**$5,532**	**$5,667**	**$6,202**	**$5,117**	**$6,704**

Future Work

In the course of conducting this study, several observations were made that suggest further refinement to these results should be considered:

- The market price reduction estimated as part of the present study will have to be ascertained as PV develops and penetrates the NJ and PA grids. In particular, the impact of PV-induced price reduction on load growth, hence feedback secondary load-growth induced market price increase as suggested by Felder [32] should be quantified. In addition, the feedback of market price reduction on capacity markets will have to be investigated.

- In this study 15% PV capacity penetration was assumed-- amounting to a total PV capacity of 7GW across the seven considered utility hubs. Since both integration cost increases and capacity value diminishes with penetration, it will be worthwhile to investigate other penetration scenarios. This may be particularly useful for PA where the penetration is smaller than NJ. In addition, it may be useful to see the scenarios with penetration above 15%. For these cases, it would be pertinent to establish the cost of displacing (nuclear) baseload generation with solar generation[4] since this question is often brought to the forefront by environmentally-concerned constituents in densely populated areas of NJ and PA.

- Other sensitivities may be important to asses as well. Sensitivities to fuel price assumptions, discount rates, and other factors could be investigated further.

- The T&D values derived for the present analysis are based on utility-wide average loads. Because this value is dependent upon the considered distribution system's characteristics – in particular load growth, customer mix and equipment age – the T&D value may vary considerably from one distribution feeder to another. It would therefore be advisable to take this study one step further and systematically identify the highest value areas. This will require the collaboration of the servicing utilities to provide relevant subsystem data.

[4] Considering integration solutions including storage, wind/PV synergy and gas generation backup.

Appendix 1: Detailed Assumptions

Input assumptions that are common across all of the scenarios are shown in Table 6.

Table 6. Input assumptions and units common to all scenarios.

INPUT ASSUMPTIONS		
PV Characteristics		
PV Degradation	0.50%	per year
PV System Life	30	years
Generation Factors		
Gen Capacity Cost	$1,045	per kW
Gen Heat Rate (First Year)	7050	BTU/kWh
Gen Plant Degradation	0.00%	per year
Gen O&M Cost (First Year)	$12.44	per MWh
Gen O&M Cost Escalation	3.38%	per year
Garver Percentage	5.00%	Pct of Ann Peak
NG Wholesale Market Factors		
End of Term NG Futures Price Escalation	2.33%	per year

PV degradation is assumed to be 0.50% per year indicating that the output of the system will degrade over time. This is a conservative assumption (PV degradation is likely to be less than 0.5% per year). Studies often ignore degradation altogether because the effect is small, but it is included here for completeness.

The study period is taken as 30 years, corresponding to typical PV lifetime assumptions.

PV is assumed to displace power generated from peaking plants fueled by natural gas. Gas turbine capital, O&M, heat rate, and escalation values are taken from the EIA.[5] Plant degradation is assumed to be zero.

[5] Updated Capital Cost Estimates for Electricity Generation Plants, U.S. Energy Information Administration, November 2010, available at http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf. Taken from Table 1, page 7. Costs are escalated to 2012 dollars.

Costs for generation O&M are assumed to escalate at 3.38%, calculated from the change in Producer Price Index (PPI) for the "Turbine and power transmission equipment manufacturing" industry[6] over the period 2004 to 2011.

Natural gas prices used in the fuel price savings value calculation are obtained from the NYMEX futures prices. These prices, however, are only available for the first 12 years. Ideally, one would have 30 years of futures prices. As a proxy for this value, it is assumed that escalation after year 12 is constant based on historically long term prices to cover the entire 30 years of the PV service life (years 13 to 30). The EIA published natural gas wellhead prices from 1922 to the present.[7] It is assumed that the price of the NG futures escalates at the same rate as the wellhead prices.[8] A 30-year time horizon is selected with 1981 gas prices at $1.98 per thousand cubic feet and 2011 prices at $3.95. This results in a natural gas escalation rate of 2.33%.

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[6] PPI data is downloadable from the Bureau industry index selected was taken as the most representative of power generation O&M. BLS does publish an index for "Electric power generation" but this is assumed.

[7] US Natural Gas Prices (Annual), EIA, release date 2/29/2012, available at http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm.

[8] The exact number could be determined by obtaining over-the-counter NG forward prices.

Appendix 2: Methodologies

Overview

The methodologies used in the present project drew upon studies performed by CPR for other states and utilities. In these studies, the key value components provided by PV were determined by CPR, using utility-provided data and other economic data.

The ability to determine value on a site-specific basis is essential to these studies. For example, the T&D Capacity Value component depends upon the ability of PV to reduce peak loads on the circuits. An analysis of this value, then, requires:

Hour by hour loads on distribution circuits of interest.

- Hourly expected PV outputs corresponding to the location of these circuits and expected PV system designs.
- Local distribution expansion plan costs and load growth projections.

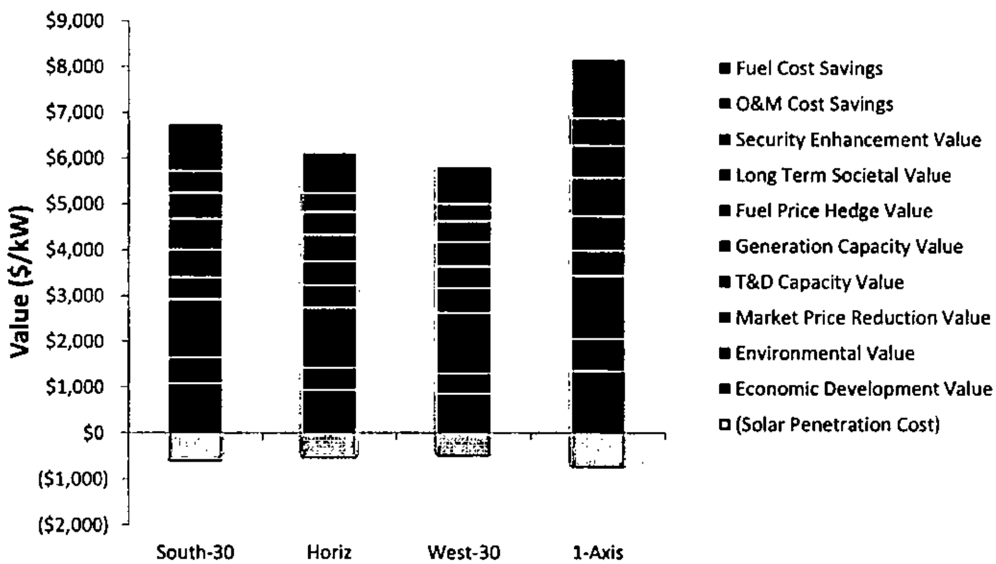
Units of Results

The discounting convention assumed throughout the report is that energy-related values occur at the end of each year and that capacity-related values occur immediately (i.e., no discounting is required).[9]

The Present Value results are converted to per unit value (Present Value $/kW) by dividing by the size of the PV system (kW). An example of this conversion is illustrated in Figure 3 for results from a previous study. The y-axis presents the per unit value and the x-axis presents seven different PV system configurations. The figure illustrates how value components can be significantly affected by PV system configuration. For example, the tracking systems, by virtue of their enhanced energy production capability, provide greater generation benefits.

[9] The effect of this will be most apparent in that the summations of cash flows start with the year equal to 1 rather than 0.

Figure 3. Sample results.



The present value results per unit of capacity ($/kW) are converted to levelized value results per unit of energy ($/MWh) by dividing present value results by the total annual energy produced by the PV system and then multiplying by an economic factor.

PV Production and Loss Savings

PV System Output

An accurate PV value analysis begins with a detailed estimate of PV system output. Some of the energy-based value components may only require the total amount of energy produced per year. Other value components, however, such as the energy loss savings and the capacity-based value components, require hourly PV system output in order to determine the technical match between PV system output and the load. As a result, the PV value analysis requires time-, location-, and configuration-specific PV system output data.

For example, suppose that a utility wants to determine the value of a 1 MW fixed PV system oriented at a 30° tilt facing in the southwest direction located at distribution feeder "A". Detailed PV output data that is time- and location-specific is required over some historical period, such as from Jan. 1, 2001 to Dec. 31, 2010.

Methodology

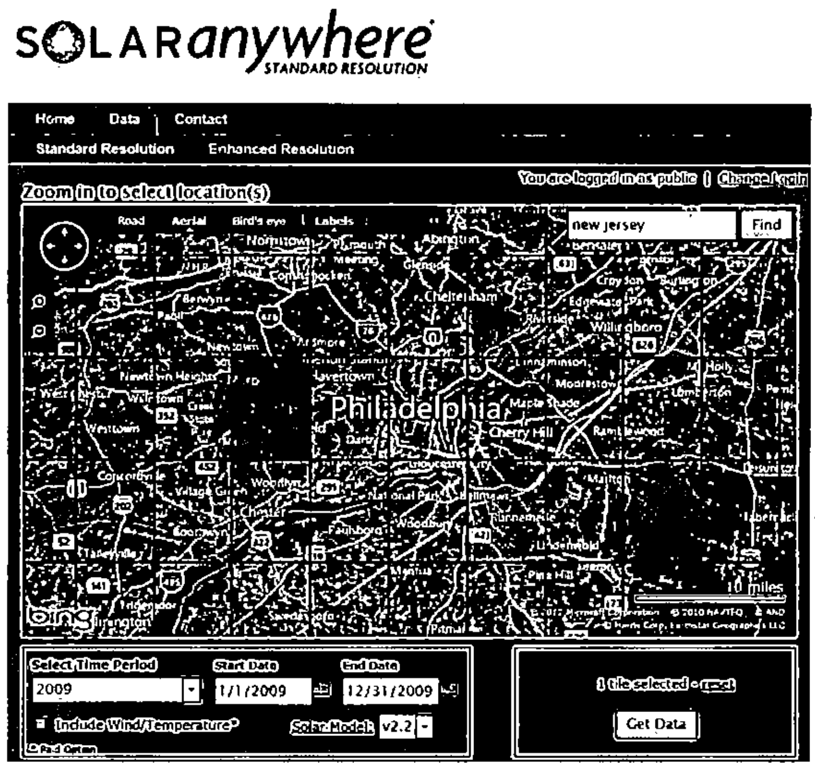
It would be tempting to use a representative year data source such as NREL's Typical Meteorological Year (TMY) data for purposes of performing a PV value analysis. While these data may be representative of long-term conditions, they are, by definition, not time-correlated with actual distribution line loading on an hourly basis and are therefore not usable in hourly side-by-side comparisons of PV and load. Peak substation loads measured, say, during a mid-August five-day heat wave must be analyzed alongside PV data that reflect the same five-day conditions. Consequently, a technical analysis based on anything other than time- and location-correlated solar data may give incorrect results.

CPR's SolarAnywhere® and PVSimulator™ software services will be employed under this project to create time-correlated PV output data. SolarAnywhere is a solar resource database containing almost 14 years of time- and location-specific, hourly insolation data throughout the continental U.S. and Hawaii. PVSimulator, available in the SolarAnywhere Toolkit, is a PV system modeling service that uses this hourly resource data and user-defined physical system attributes in order to simulate configuration-specific PV system output.

The SolarAnywhere data grid web interface is available at www.SolarAnywhere.com (Figure 4). The structure of the data allows the user to perform a detailed technical assessment of the match between PV system output and load data (even down to a specific feeder). Together, these two tools enable the evaluation of the technical match between PV system output and loads for any PV system size and orientation.

Previous PV value analyses were generally limited to a small number of possible PV system configurations due to the difficulty in obtaining time- and location-specific solar resource data. This new value analysis software service, however, will integrate seamlessly with SolarAnywhere and PVSimulator. This will allow users to readily select any PV system configuration. This will allow for the evaluation of a comprehensive set of scenarios with essentially no additional study cost.

Figure 4. SolarAnywhere data selection map.



Loss Savings

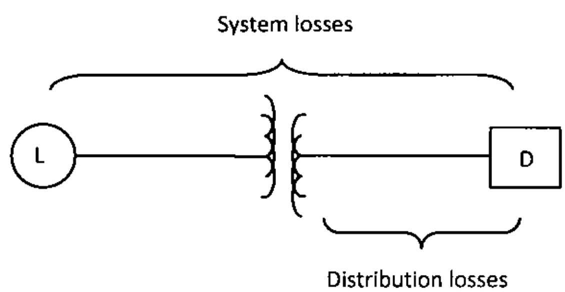
Introduction

Distributed resources reduce system losses because they produce power in the same location that the power is consumed, bypassing the T&D system and avoiding the associated losses.

Loss savings are not treated as a stand-alone benefit under the convention used in this methodology. Rather, the effect of loss savings is included separately for each value component. For example, in the section that covers the calculation of Energy Value, the quantity of energy saved by the utility includes both the energy produced by PV and the amount that would have been lost due to heating in the wires if the load were served from a remote source. The total energy that would have been procured by the utility equals the PV energy plus avoided line losses. Loss savings can be considered a sort of "adder" for each benefit component.

This section describes the methodology for calculating loss savings for each hour. The results of these calculations are then used in subsequent sections. As illustrated in Figure 5, it will be important to note that, while the methodology describes the calculation of an hourly loss result, there are actually two different loss calculations that must be performed: "system" losses, representing the losses incurred on both the transmission and distribution systems (between generation load, L, and end-use demand, D), and "distribution" losses, representing losses specific to distribution system alone.

Figure 5. System losses versus distribution losses.



The two losses are calculated using the same equation, but they are each applicable in different situations. For example, "Energy Value" represents a benefit originating at the point of central generation, so that the total system losses should be included. On the other hand, "T&D Capacity Value" represents a benefit as measured at a distribution substation. Therefore, only the losses saved on the distribution system should be considered.

The selection of "system" versus "distribution" losses is discussed separately for each subsequent benefit section.

Methodology

One approach analysts have used to incorporate losses is to adjust energy- and capacity-related benefits based on the *average* system losses. This approach has been shown to be deficient because it fails to capture the true reduction in losses on a marginal basis. In particular, the approach underestimates the reduction in losses due to a peaking resource like PV. Results from earlier studies demonstrated that loss savings calculations may be off by more than a factor of two if not performed correctly [6].

For this reason, the present methodology will incorporate a calculation of loss savings on a marginal basis, taking into account the status of the utility grid when the losses occur. Clean Power Research has previously developed methodologies based on the assumption that the distributed PV resource is small relative to the load (e.g., [6], [9]). CPR has recently completed new research that expands this methodology so that loss savings can now be determined for any level of PV penetration.

Fuel Cost Savings and O&M Cost Savings

Introduction

Fuel Cost Savings and O&M Cost Savings are the benefits that utility participants derive from using distributed PV generation to offset wholesale energy purchases or reduce generation costs. Each kWh generated by PV results in one less unit of energy that the utility needs to purchase or generate. In addition, distributed PV reduces system losses so that the cost of the wholesale generation that would have been lost must also be considered. The capacity value of generation is treated in a separate section.

Methodology

These values can be calculated by multiplying PV system output times the cost of the generation on the margin for each hour, summing for all hours over the year, and then discounting the results for each year over the life of the PV system.

There are two approaches to obtaining the marginal cost data. One approach is to obtain the marginal costs based on historical or projected market prices. The second approach is to obtain the marginal costs based on the cost of operating a representative generator that is on the margin.

Initially, it may be appealing to take the approach of using market prices. There are, however, several difficulties with this approach. One difficulty is that these tend to be hourly prices and thus require hourly PV system output data in order to calculate the economic value. This difficulty can be addressed by using historical prices and historical PV system output to evaluate what results would have been in the past and then escalating the results for future projections. A more serious difficulty is that, while hourly market prices could be projected for a few years into the future, the analysis needs to be performed over a much longer time period (typically 30 years). It is difficult to accurately project hourly market prices 30 years into the future.

A more robust approach is to explicitly specify the marginal generator and then to calculate the cost of the generation from this unit. This is often a Combined Cycle Gas Turbine (CCGT) powered using natural gas (e.g., [6]). This approach includes the assumption that PV output always displaces energy from the same marginal unit. Given the uncertainties and complications in market price projections, the second approach is taken.

Fuel Cost Savings and O&M Cost Savings equals the sum of the discounted fuel cost savings and the discounted O&M cost savings.

Security Enhancement Value

Because solar generation is closely correlated with load in much of the US, including New Jersey and Pennsylvania [26], the injection of solar energy near point of use can deliver effective capacity, and therefore reduce the risk of the power outages and rolling blackouts that are caused by high demand and resulting stresses on the transmission and distribution systems.

The effective capacity value of PV accrues to the ratepayer (see above) both at the transmission and distribution levels. It is thus possible to argue that the reserve margins required by regulators would account for this new capacity, hence that no increased outage risk reduction capability would occur beyond the pre-PV conditions. This is the reason this value item above is not included as one of the directly quantifiable attributes of PV.

On the other hand there is ample evidence that during heat wave-driven extreme conditions, the availability of PV is higher than suggested by the effective capacity (reflecting of all conditions) -- e.g., see [27], [28], on the subject of major western and eastern outages, and [29] on the subject of localized rolling blackouts. In addition, unlike conventional centralized generation injecting electricity (capacity) at specific points on the grid, PV acts as a load modulator that provides immediate stress relief throughout the grid where stress exists due to high-demand conditions. It is therefore possible to argue that, all conditions remaining the same in terms of reserve margins, a load-side dispersed PV resource would mitigate issues leading to high-demand-driven localized and regional outages.

Losses resulting from power outages are generally not a utility's (ratepayers') responsibility: society pays the price, via losses of goods and business, compounded impacts on the economy and taxes, insurance premiums, etc. The total cost of all power outages from all causes to the US economy has been estimated at $100 billion per year (Gellings & Yeager, 2004). Making the conservative assumption that a small fraction of these outages, 5%, are of the high-demand stress type that can be effectively mitigated by dispersed solar generation at a capacity penetration of 15%,[10] it is straightforward to calculate, as shown below, that, nationally, the value of each kWh generated by such a dispersed solar base would be of the order of $20/MWh to the taxpayer.

The US generating capacity is roughly equal to 1000 GW. At 15% capacity penetration, taking a national average of 1500 kWh (slightly higher nationwide than PA and NJ) generated per year per installed kW, PV would generate 225,000 GWh/year. By reducing the risk of outage by 5%, the value of this energy would thus be worth $5 billion, amounting to $20 per PV-generated MWh.

This national value of $20 per MWh was taken for the present study because the underlying estimate of cost was available on a national basis. In reality, there would be state-level differences from this estimate, but these are not available.

Long Term Societal Value

This item is an attempt to place a present-value $/MWh on the generally well accepted argument that solar energy is a good investment for our children and grandchildren's well-being. Considering:

1. The rapid growth of large new world economies and the finite reserves of conventional fuels now powering the world economies, it is likely that fuel prices will continue rise exponentially fast for the long term beyond the 30-year business life cycle considered here.
2. The known very slow degradation of the leading (silicon) PV technology, many PV systems installed today will continue to generate power at costs unaffected by the world fuel markets after their guaranteed lifetimes of 25-30 years

One approach to quantify this type of long-view attribute has been to apply a very low societal discount rate (e.g., 2% or less, see [25]) to mitigate the fact that the present-day importance of long-term expenses/benefits is essentially ignored in business as usual practice. This is because discount rates are

[10] Much less than that would have prevented the 2003 NE blackout. See [30].

used to quantify the present worth of future events and that, and therefore, long-term risks and attributes are largely irrelevant to current decision making.

Here a less controversial approach is proposed by arguing that, on average, PV installation will deliver, on average, a minimum of 10 extra years of essentially free energy production beyond the life cycle considered in this study.

The present value of these extra 10 years, all other assumptions on fuel cost escalation, inflation, discount rate, PV output degradation, etc. remaining the same, amounts to ~ $25/MWh for all the cities/PJM hubs considered in this study.

Fuel Price Hedge Value

Introduction

Solar-based generation is insensitive to the volatility of fuel prices while fossil-based generation is directly tied to fuel prices. Solar generation, therefore, offers a "hedge" against fuel price volatility. One way this has been accounted for is to quantify the value of PV's hedge against fluctuating natural gas prices [6].

Methodology

The key to calculating the Fuel Price Hedge Value is to effectively convert the fossil-based generation investment from one that has substantial fuel price uncertainty to one that has no fuel price uncertainty. This can be accomplished by entering into a binding commitment to purchase a lifetime's worth of fuel to be delivered as needed. The utility could set aside the entire fuel cost obligation up front, investing it in risk-fee securities to be drawn from each year as required to meet the obligation. The approach uses two financial instruments: risk-free, zero-coupon bonds[11] and a set of natural gas futures contracts.

Consider how this might work. Suppose that the CCGT operator wants to lock in a fixed price contract for a sufficient quantity of natural gas to operate the plant for one month, one year in the future. First, the operator would determine how much natural gas will be needed. If E units of electricity are to be generated and the heat rate of the plant is H, $E * H$ BTUs of natural gas will be needed. Second, if the corresponding futures price of this natural gas is $P^{NG\ Futures}$ (in $ per BTU), then the operator will need $E *$

[11] A zero coupon bond does not make any periodic interest payments.

$H * P^{NG\ Futures}$ dollars to purchase the natural gas one year from now. Third, the operator needs to set the money aside in a risk-free investment, typically a risk-free bond (rate-of-return of $r^{risk\text{-}free}$ percent) to guarantee that the money will be available when it is needed one year from now. Therefore, the operator would immediately enter into a futures contract and purchase $E * H * P^{NG\ Futures} / (1+ r^{risk\text{-}free})$ dollars worth of risk-free, zero-coupon bonds in order to guarantee with certainty that the financial commitment (to purchase the fuel at the contract price at the specified time) will be satisfied.[12]

This calculation is repeated over the life of the plant to calculate the Fuel Price Hedge value.

Generation Capacity Value

Introduction

Generation Capacity Value is the benefit from added capacity provided to the generation system by distributed PV. Two different approaches can be taken to evaluating the Generation Capacity Value component. One approach is to obtain the marginal costs based on market prices. The second approach is to estimate the marginal costs based on the cost of operating a representative generator that is on the margin, typically a Combined Cycle Gas Turbine (CCGT) powered by natural gas.

Methodology

The second approach is taken here for purposes of simplicity. Future version of the software service may add a market price option.

Once the cost data for the fully-dispatchable CCGT are obtained, the match between PV system output and utility loads needs to be determined in order to determine the effective value of the non-dispatchable PV resource. CPR developed a methodology to calculate the effective capacity of a PV system to the utility generation system (see [10] and [11]) and Perez advanced this method and called it the Effective Load Carrying Capability (ELCC) [12]. The ELCC method has been identified by the utility industry as one of the preferable methods to evaluate PV capacity [13] and has been applied to a variety of places, including New York City [14].

The ELCC is a statistical measure of effective capacity. The ELCC of a generating unit in a utility grid is defined as the load increase (MW) that the system can carry while maintaining the designated reliability

[12] $[E * H * P^{NG\ Futures} / (1+ r^{risk\text{-}free})] * (1+ r^{risk\text{-}free}) = E * H * P^{NG\ Futures}$

criteria (e.g., constant loss of load probability). The ELCC is obtained by analyzing a statistically significant time series of the unit's output and of the utility's power requirements.

Generation Capacity Value equals the capital cost ($/MW) of the displaced generation unit times the effective capacity provided by the PV.

T&D Capacity Value

Introduction

The benefit that can be most affected by the PV system's location is the T&D Capacity Value. The T&D Capacity Value depends on the existence of location-specific projected expansion plan costs to ensure reliability over the coming years as the loads grow. Capacity-constrained areas where loads are expected to reach critical limits present more favorable locations for PV to the extent that PV will relieve the constraints, providing more value to the utility than those areas where capacity is not constrained.

Distributed PV generation reduces the burden on the distribution system. It appears as a "negative load" during the daylight hours from the perspective of the distribution operator. Distributed PV may be considered equivalent to distribution capacity from the perspective of the distribution planner, provided that PV generation occurs at the time of the local distribution peak.

Distributed PV capacity located in an area of growing loads allows a utility planner to defer capital investments in distribution equipment such as substations and lines. The value is determined by the avoided cost of money due to the capital deferral.

Methodology

It has been demonstrated that the T&D Capacity Value can be quantified in a two-step process. The first step is to perform an economic screening of all areas to determine the expansion plan costs and load growth rates for each planning area. The second step is to perform a technical load-matching analysis for the most promising locations [18].

Market Price Reduction Value

Two cost savings occur when distributed PV generation is deployed in a market that is structured where the last unit of generation sets the price for all generation and the price is an increasing function of load. First, there is the direct savings that occur due to a reduction in load. This is the same as the value of energy provided at the market price of power. Second, there is the indirect value of market price reduction. Distributed generation reduces market demand and this results in lower prices to all those purchasing power from the market. This section outlines how to calculate the market savings value.

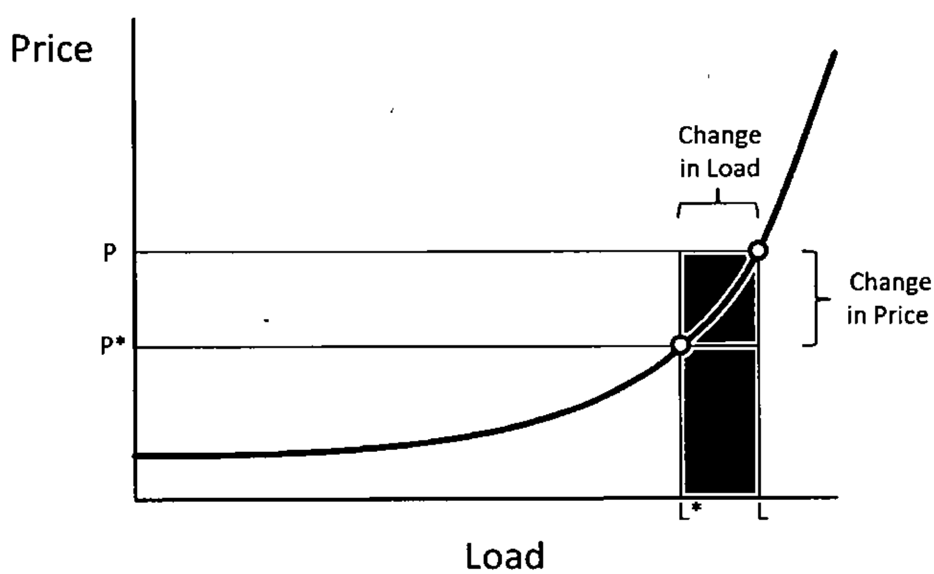
Cost Savings

As illustrated in Figure 6, the total market expenditures at any given point in time are based on the current price of power (P) and the current load (L). The rate of expenditure equals P L. Total market expenditures after PV is deployed equals the new price (P*) times the new load (L*), or P*L*. Cost savings equal the difference between the total before and after expenditures.

$$Cost\ Savings = P\ L - P^{*}L^{*} \tag{1}$$

The figure illustrates that the cost savings occur because there is both a change in load and a change in price.

Figure 6. Illustration of price changes that occur in market as result of load changes.



Equation (1) can be expanded by adding $-P^{*}L + P^{*}L$ and then rearranging the result.

$$Cost\ Savings \quad = P\ L + (-P^{*}L + P^{*}L) - P^{*}L^{*} \tag{2}$$

$$= (P - P^*)L + P^*(L - L^*)$$

$$= \left[\left(\frac{P - P^*}{L - L^*}\right) L + P^*\right] (L - L^*)$$

Let $\Delta L = L - L^*$ and $\Delta P = P - P^*$ and substitute into Equation (2). The result is that

$$Cost\ Savings = \left[P + \frac{\Delta P}{\Delta L} L - \Delta P\right] \Delta L \tag{3}$$

Per unit cost savings is obtained by dividing Equation (3) by ΔL.

$$Per\ Unit\ Cost\ Savings = \overbrace{P}^{Direct\ Savings} + \overbrace{\frac{\Delta P}{\Delta L} L - \Delta P}^{Market\ Price\ Reduction\ Value} \tag{4}$$

Discussion

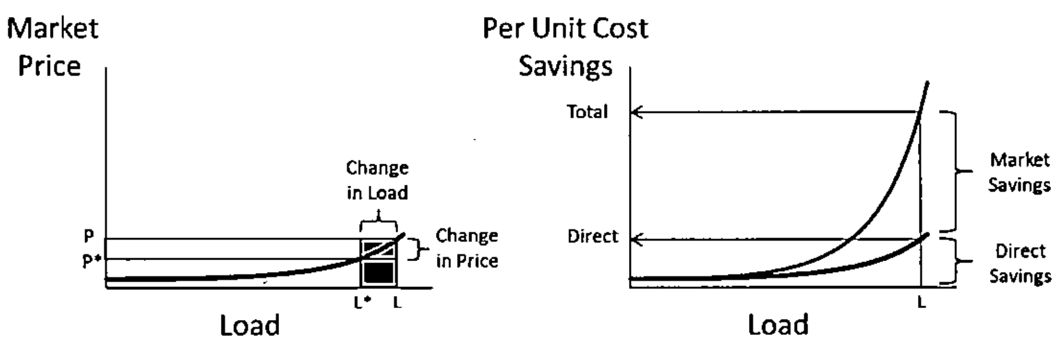
Equation (4) suggests that there are two cost savings components: direct savings and market price suppression. The direct savings equal the existing market price of power. The market price reduction value is the savings that the entire market realizes as a result of the load reduction. These savings depends on the change in load, change in price, and existing load. It is important to note that the change in load and the existing load can be measured directly while the change in price cannot be measured directly. This means that the change in price must be modeled (rather than measured).

It is useful to provide an interpretation of the market price reduction component and illustrate the potential magnitude. The market price reduction component in Equation (4) has two terms. The first term is the slope of the price curve (i.e., it is the derivative as the change in load goes to zero) times the existing load. This is the positive benefit that the whole market obtains due to price reductions. The second term is the reduced price associated with the direct savings.

The left side of Figure 7 presents the same information as in Figure 6, but zooms out on the y-axis scale of the chart. The first term corresponds to the yellow area. The second term corresponds to the overlapping areas of the change in price and change in load effects.

The market price curve can be translated to a cost savings curve. The right side of Figure 7 presents the per unit cost savings based on the information from the market price curve (i.e., the left side of the figure). The lower black line is the price vs. load curve. The upper line adds the market price suppression component to the direct savings component. It assumes that there is the same load reduction for all loads as in the left side of the figure. The figure illustrates that no market price suppression exist when the load is low but the market price suppression exceed the direct cost savings when the load is high. The saving is dependent upon the shape of the price curve and the size of the load reduction.

Figure 7. Direct + market price reduction vs. load (assuming constant load reduction).



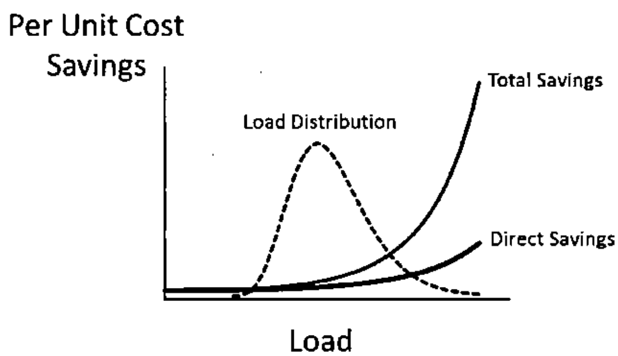
Total Value

The previous sections calculated the cost savings at a specific instant in time. The total cost savings is calculated by summing this result overall all periods in time. The per unit cost savings is calculated by dividing by the total energy. (Note that it is assumed that each unit of time represents 1 unit). The result is that:

$$Per\ Unit\ Cost\ Savings = \frac{Total\ Cost\ Savings}{Total\ Energy} = \frac{\sum_{t=1}^{T}\left[P_t + \frac{\Delta P_t}{\Delta L_t}L_t - \Delta P_t\right]\Delta L_t}{\sum_{t=1}^{T}\Delta L_t} \quad (5)$$

This result can be viewed graphically as the probability distribution of the load times the associate cost savings curves when there is a constant load reduction. Multiply the load distribution by the total per unit savings to obtain the weighted average per unit cost savings.

Figure 8. Apply load distribution to calculate total savings over time.



Application

As discussed above, all of the parameters required to perform this calculation can be measured directly except for the change in price. Thus, it is crucial to determine how to estimate the change in price.

This is implemented in four steps:

1. Obtain LMP price data and develop a model that reflects this data.
2. Use the LMP price model and Equation (4) to calculate the price suppression benefit. Note that this depends upon the size of the change in load.
3. Obtain time-correlated PV system output and determine the distribution of this output relative to the load.
4. Multiply the PV output distribution times the price suppression benefit to calculate the weighted-average benefit.

Historical LMP and time- and location-correlated PV output data are required to perform the analysis. LMPs are obtained from the market and the PV output data are obtained by simulating time- and location-specific PV output using SolarAnywhere.

Figure 9 illustrates how to perform the calculations using measured prices and simulated PV output for PPL in June 2012. The left side of the figure illustrates that the historical LMPs (black circles) are used to develop a price model (solid black line). The center of the figure illustrates how the price model is used with Equation (4) is used to calculate the price suppression benefit for every load level. Since this benefit depends upon the size of the change in the load, the figure presents a range. The solid blue line is the benefit for a very small PV output. The dashed blue line corresponds to the benefit for a 1,000 MW PV output. The right side of the figure (red line) presents the distribution of the PV energy relative to the load (i.e., the amount of PV energy produced at each load level, so higher values correspond to more frequent weighting). The weighted-average price suppression benefit is calculated by multiply the PV output distribution times the price suppression benefit. Note that in practice, the actual calculation is performed for each hour of the analysis since the price suppression benefit is a function of both the load and the PV output.

Figure 9. Illustration of how to calculate benefit using measured data for June 2011.

Step 1:	Step 2:	Step 3:
Develop price model based on measured LMP data	Calculate price reduction benefit (depends on output)	Develop PV output distribution

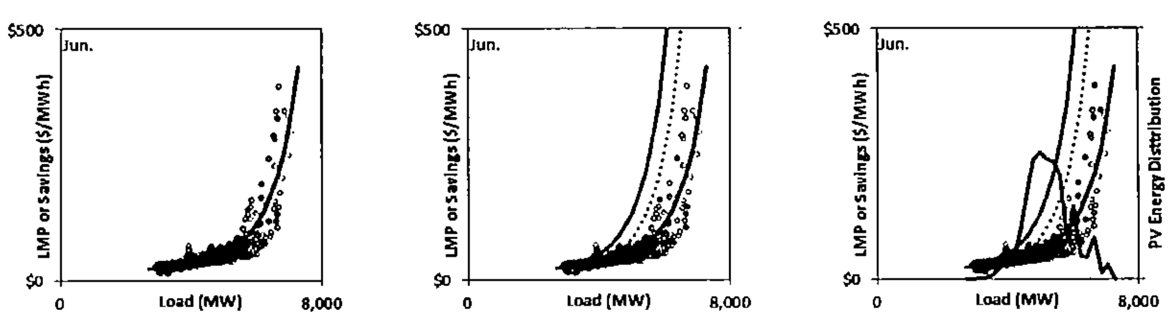
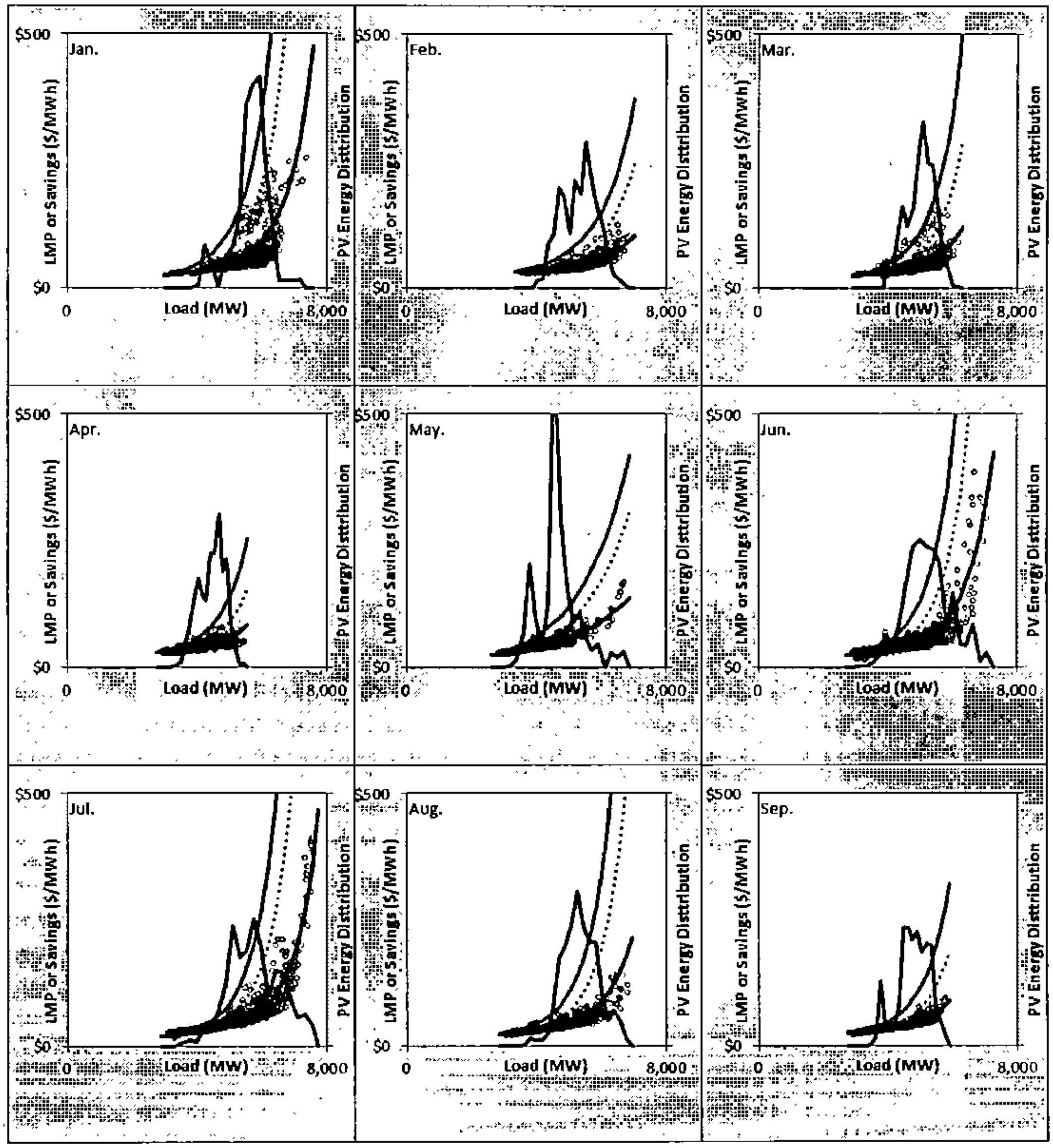
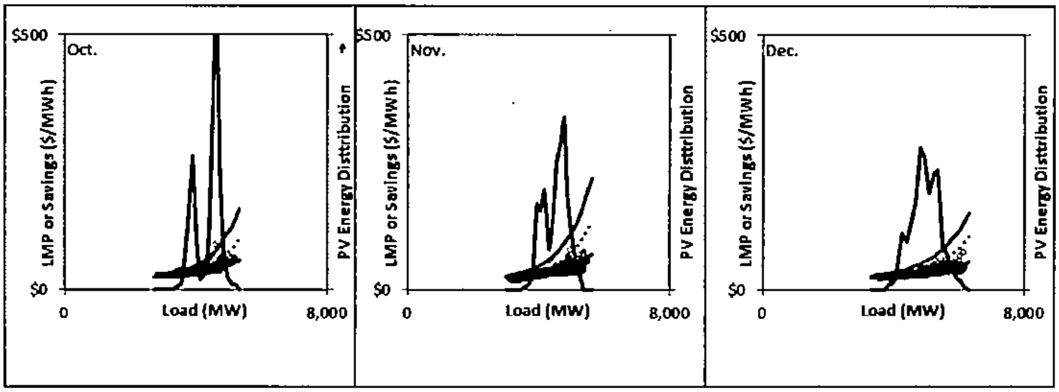


Figure 10 presents the results for the three steps for each month in 2011.

Figure 10. Measured and modeled LMPs (black circles and lines), price suppression benefit (solid blue for small output and dashed blue for 1,000 MW of output) and PV output distribution (PPL 2011).





Results

As illustrated in Table 7 the price reduction benefits are more than double the direct savings for a 100 MW of PV and slightly exceed the direct saving for 1,000 MW PV, for a combined value ranging from $127/MWh to $180/MWh.

Table 7. Market savings illustration.

	100 MW	1,000 MW
Direct Savings	$58	$58
Market Price Reduction	$122	$69
Total	$180	$127

A comparison of direct market savings and energy savings as calculated in this study is shown in Table 8. Fuel cost savings and O&M cost savings are combined because they represent the same costs that are included in market price. Direct savings were calculated for each hour as $P \cdot \Delta L$, summed for the year, and escalated at the same rate each year as natural gas futures beyond the 12 year limit.

Table 8. Direct market savings comparison (Newark, South-30).

	Value ($/kW)	Value ($/MWh)
Fuel Cost Savings	$709	38.8
O&M Cost Savings	$345	18.9
Total Energy Savings	**$1,054**	**57.7**
Direct Market Savings	**$1,470**	**80.4**

The results show that direct market savings are 39% above the energy savings. This discrepancy reflects the fact that the two quantities, while representing the same value components, use entirely different approaches. Fuel cost savings are derived from natural gas futures, discounted at the utility discount rate, and applied against an assumed CCGT heat rate. Direct market savings are based on hourly PJM zonal prices for 2011.

The energy savings achieved by the utility is based on avoided market purchases. However, historical market prices are not necessarily and indicator of future years, especially for 30 years into the future. For this reason, the energy savings methodology used in this analysis is more closely tied to the fundamentals of the cost: fuel and O&M costs that must be recovered by the marketplace for generation to be sustainable in the long run.

Zonal Price Model

To calculate the market price reduction in equation (4), a zonal price model was developed as follows. A function F() may be defined whose value is proportional to market clearing price using the form:

$$F(Load) = Ae^{BxLoad^{C}+D}$$

where coefficients A, B, C, and D are evaluated for each utility and for each month using hourly PJM zonal market price data, amounting to a total of 84 individual models.

P is the zonal wholesale clearing price, and P* is given by:

$$\frac{P^*}{P} = \frac{F(Load - FleetPower - LossSavings)}{F(Load)}$$

The market price reduction (in $/MWh) is calculated using the relevant term in Equation (4) and multiplying by the change in load, including loss savings.

Environmental Value

Introduction

It is well established that the environmental impact of PV is considerably smaller than that of fossil-based generation since PV is able to displace pollution associated with drilling/mining, and power plant emissions [15].

Methodology

There are two general approaches to quantifying the Environmental Value of PV: a regulatory cost-based approach and an environmental/health cost-based approach.

The regulatory cost-based approach values the Environmental Value of PV based on the price of Renewable Energy Credits (RECs) or Solar Renewable Energy Credits (SRECs) that would otherwise have to be purchased to satisfy state Renewable Portfolio Standards (RPS). These costs are a preliminary legislative attempt to quantify external costs. They represent actual business costs faced by utilities in certain states.

An environmental/health cost-based approach quantifies the societal costs resulting from fossil generation. Each solar kWh displaces an otherwise dirty kWh and commensurately mitigates several of the following factors: greenhouse gases, SOx/NOx emissions, mining degradations, ground water contamination, toxic releases and wastes, etc., that are all present or postponed costs to society. Several exhaustive studies have estimated the environmental/health cost of energy generated by fossil-based generation [16], [17]. The results from environmental/health cost-based approach often vary widely and can be controversial.

The environmental/health cost-based approach was used for this study.

The environmental footprint of solar generation is considerably smaller than that of the fossil fuel technologies generating most of our electricity (e.g., [19]). Utilities have to account for this environmental impact to some degree today, but this is still only largely a potential cost to them. Rate-based Solar Renewable Energy Credits (SRECs) markets in New Jersey and Pennsylvania as a means to meet Renewable Portfolio Standards (RPS) are a preliminary embodiment of including external costs, but they are largely driven more by politically-negotiated processes than by a reflection of inherent physical realities. The intrinsic physical value of displacing pollution is real and quantifiable however: depending on the current generation mix, each solar kWh displaces an otherwise dirty kWh and commensurately mitigates several of the following factors: greenhouse gases, SOx/NOx emissions, mining degradations, ground water contamination, toxic releases and wastes, etc., which are all present or postponed costs to society (i.e., the taxpayers).

The environmental value, EV, of each kWh produced by PV (i.e., not produced by another conventional source) is given by:

$$EV = \sum_{i=0}^{n} x_i \, EC_i$$

Where EC_i is the environmental cost of the displaced conventional generation technology and x_i is the proportion of this technology in the current energy mix.

Several exhaustive studies emanating from such diverse sources as the nuclear industry or the medical community ([20], [21]) estimate the environmental/health cost of 1 MWh generated by coal at $90-250, while a [non-shale[13]] natural gas MWh has an environmental cost of $30-60.

Considering New Jersey and Pennsylvania's electrical generation mixes (Table 9) and assuming that (1) nuclear energy is not displaced by PV at the assumed penetration level[14] and (2) that all natural gas is conventional, the environmental value of each MWh displaced by PV, hence the taxpayer benefit, is estimated at $48 to $129 in Pennsylvania and $20 to $48 in New Jersey.

We retained a value near the lower range of these estimates for the present analysis.

[13] Shale gas environmental footprint is likely higher both in terms of environment degradation and GHG emissions.

[14] The study therefore ascribes no environmental value related to nuclear generation. Scenarios can certainly be designed in which nuclear generation would be displaced, in which case the environmental cost of nuclear generation would have to be considered. This is a complex and controversial subject that reflects the probability of catastrophic accidents and the environmental footprint of the existing uranium cycle. The fact that the environmental liability is assumed to be zero under the present study may therefore be considered a conservative case.

Table 9. Environmental input calculation.

	Generation Mix		Prorated Environmental Cost ($/MWh)		
Pennsylvania	48%	Coal	43.2	to	120.0
	15%	Natural Gas	4.5	to	9.0
	34%	Nuclear	0.0	to	0.0
	3%	Other	0.0	to	0.0
	Environmental Value for PA		47.7	to	129.0
New Jersey	10%	Coal	9.0	to	25.0
	38%	Natural Gas	11.4	to	22.8
	50%	Nuclear	0.0	to	0.0
	2%	Other	0.0	to	0.0
	Environmental Value for NJ		20.4	to	47.8

Economic Development Value

The German and Ontario experiences as well as the experience in New Jersey, where fast PV growth is occurring, show that solar energy sustains more jobs per unit of energy generated than conventional energy ([21], [22]). Job creation implies value to society in many ways, including increased tax revenues, reduced unemployment, and an increase in general confidence conducive to business development.

In this report, only tax revenue enhancement from the jobs created as a measure of PV-induced economic development value is considered. This metric provides a tangible low estimate of solar energy's likely larger multifaceted economic development value. In Pennsylvania and New Jersey, this low estimate amounts to respectively $39 and $40 per MWh, even under the very conservative, but thus far realistic, assumption that 80% of the PV manufacturing jobs would be either out-of-state or foreign (see methodology section, below).

Methodology

In a previous (New York) study [24], net PV-related job creation numbers were used directly based upon Ontario and Germany's historical numbers. However this assumption does not reflects the rapid changes of the PV industry towards lower prices. In this study a first principle approach is applied based upon the difference between the installed cost of PV and conventional generation: in essence this approach quantifies the fact that part of the price premium paid for PV vs. conventional generation returns to the local economy in the form of jobs hence taxes.

Therefore, assuming that:

- Turnkey PV costs $3,000 per kW vs. $1,000 per kW for combine cycle gas turbines (CCGT)
- Turnkey PV cost is composed of 1/3 technology (modules & inverter/controls) and 2/3 structure and installation and soft costs.
- 20% of the turnkey PV technology cost and 90% of the other costs are traceable to local jobs, while 50% of the CCGT are assumed to be local jobs, thus:
  - The local jobs-traceable amount spent on PV is equal to: $\left(\frac{0.2}{3}+\frac{0.9\times2}{3}\right)\times 3000 = \$1{,}990/kW$
  - And the local jobs-traceable amount spent on CCGT is equal to: $0.5\times 1000 = \$500/kW$
- PV systems in NJ and PA have a capacity factor of ~ 16%, producing 1,400 kWh per year per kW_{AC} and CCGT have an assumed capacity factor of 50%, producing 4,380 kWh per year, therefore
  - The local jobs-traceable amount spent per PV kWh in year one is: 1,900/1,400 = $1.42
  - The local jobs-traceable amount spent per CCGT kWh in year one is: 500/4,380 = $0.114
- The net local jobs-traceable between PV and CCGT is thus equal to 1.42-0.11 = $1.30
- Assuming that the life span of both PV and CCGT is 30 years, and using a levelizing factor of 8%, the net local jobs-traceable amount per generated PV kWh over its lifetime amounts to:

  $1.30\times\frac{0.08\times1.08^{30}}{1.08^{29}} = \$0.116/\text{kWh}$
- Assuming that locally-traceable O&M costs per kWh for PV are equal to the locally-traceable O&M costs for CCGT,[15] but also assuming that because PV-related T&D benefits displace a commensurate amount of utility jobs assumed to be equal to this benefit (~0.5 cents per kWh), the net lifetime locally-traceable PV-CCGT difference is equal to 0.116-0.005 = $0.111/kWh
- Finally assuming that each PV job is worth $75K/year after standard deductions – hence has a combined State and Federal income tax rate of 22.29% in PA and 22.67% in NJ[16] -- and that each

[15] This includes only a fraction of the fuel costs – the other fraction being imported from out-of-state.

[16] For the considered solar job income level, the effective state rate = 3.07% in PA and 3.54% in NJ and the effective federal rate = 19.83%. The increased federal tax collection is counted as an increase for New Jersey's

new job has an indirect job multiplier of 1.6,[17] it can be argued that each PV MWh represents a net new-job related tax collection increase for NJ equal to a levelized value of $\$111/MWh \times 0.2267 \times 1.6 = \$40/MWh$, and a tax collection increase for PA equal to $\$111/MWh \times 0.2229 \times 1.6 =$, $\$39/MWh$.

Solar Penetration Cost

It is important to recognize that there is also a cost associated with the deployment of solar generation on the power grid which accrues to the utility and to its ratepayers. This cost represents the infrastructural and operational expense that will be necessary to manage the flow of non-controllable solar energy generation while continuing to reliably meet demand. A recent study by Perez et al. [31] showed that in much of the US, this cost is negligible at low penetration and remains manageable for a solar capacity penetration of 30%. For utilities representative of the demand pattern and solar load synergies found in Pennsylvania, this penetration cost has been found to range from 0 to 5 cents per kWh when PV penetration ranges from 0% to 30% in capacity. Up to this level of penetration, the infrastructural and operational expense would consist of localized load management, [user-sited] storage and/or backup.[18] At the 15% level of penetration considered in this study, the cost of penetration can be estimated from the Perez et al. study[18] at $10-20/MWh.

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taxpayer, because it can be reasonably argued that federal taxes are (1) redistributed fairly to the states and (2) that federal expense benefit all states equally.

[17]indirect base multipliers are used to estimate the local jobs not related to the considered job source (here solar energy) but created indirectly by the new revenues emanating from the new [solar] jobs

[18] At the higher penetration levels the two approaches to consider would be regional (or continental) interconnection upgrade and smart coupling with natural gas generation and wind power generation – the cost of these approaches has not been quantified as part of this study.

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Appendix 3: Detailed Results

Pittsburgh

Table A4- 1. Technical results, Pittsburgh.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	475	475	475	475
Annual Energy Production (MWh)	716,621	631,434	595,373	892,905
Capacity Factor (%)	17%	15%	14%	21%
Generation Capacity (% of Fleet Capacity)	41%	43%	45%	48%
T&D Capacity (% of Fleet Capaccity)	31%	32%	32%	32%

Table A4- 2. Value ($/kW), Pittsburgh.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$813	$719	$678	$1,011
O&M Cost Savings	$396	$350	$331	$493
Total Energy Value	$1,209	$1,069	$1,009	$1,503
Strategic				
Security Enhancement Value	$446	$394	$372	$554
Long Term Societal Value	$557	$493	$465	$693
Total Strategic Value	$1,003	$887	$837	$1,247
Other				
Fuel Price Hedge Value	$613	$542	$512	$763
Generation Capacity Value	$432	$446	$468	$505
T&D Capacity Value	$127	$127	$130	$129
Market Price Reduction Value	$696	$718	$715	$740
Environmental Value	$1,064	$940	$888	$1,322
Economic Development Value	$870	$769	$726	$1,081
(Solar Penetration Cost)	($446)	($394)	($372)	($554)
Total Other Value	$3,355	$3,149	$3,067	$3,987
Total Value	**$5,568**	**$5,105**	**$4,913**	**$6,737**

Table A4- 3. Levelized Value ($/MWh), Pittsburgh.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$41	$41	$41	$41
O&M Cost Savings	$20	$20	$20	$20
Total Energy Value	$61	$61	$62	$61
Strategic				
Security Enhancement Value	$23	$23	$23	$23
Long Term Societal Value	$28	$28	$28	$28
Total Strategic Value	$51	$51	$51	$51
Other				
Fuel Price Hedge Value	$31	$31	$31	$31
Generation Capacity Value	$22	$26	$29	$21
T&D Capacity Value	$6	$7	$8	$5
Market Price Reduction Value	$35	$41	$44	$30
Environmental Value	$54	$54	$54	$54
Economic Development Value	$44	$44	$44	$44
(Solar Penetration Cost)	($23)	($23)	($23)	($23)
Total Other Value	$170	$181	$187	$162
Total Value	**$282**	**$293**	**$300**	**$274**

Figure A4- 1. Value ($/kW), Pittsburgh.

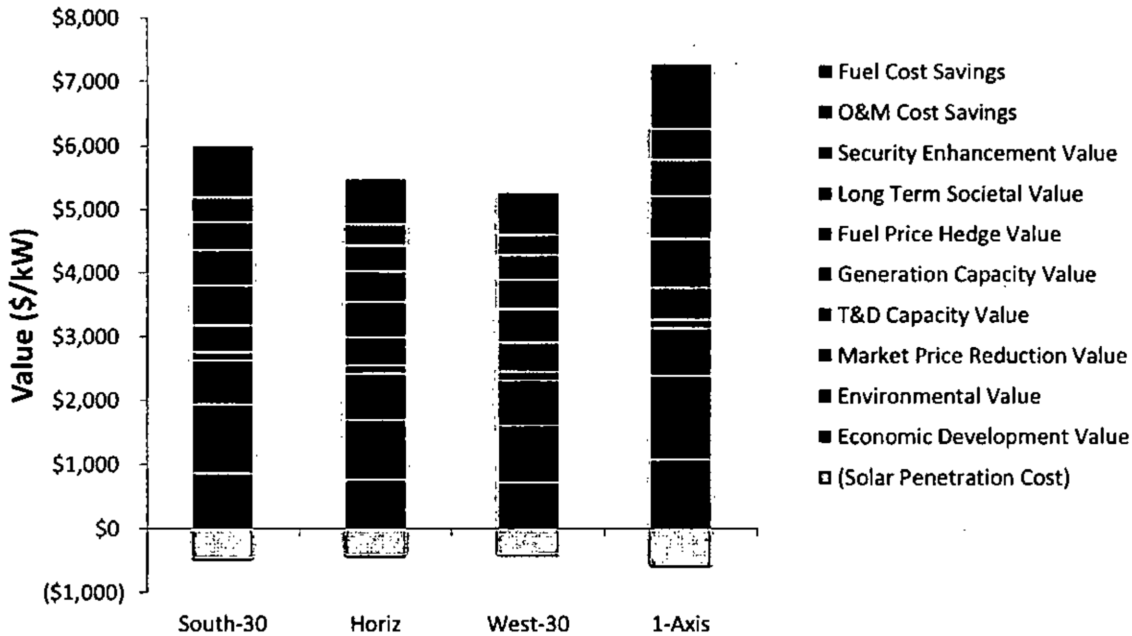
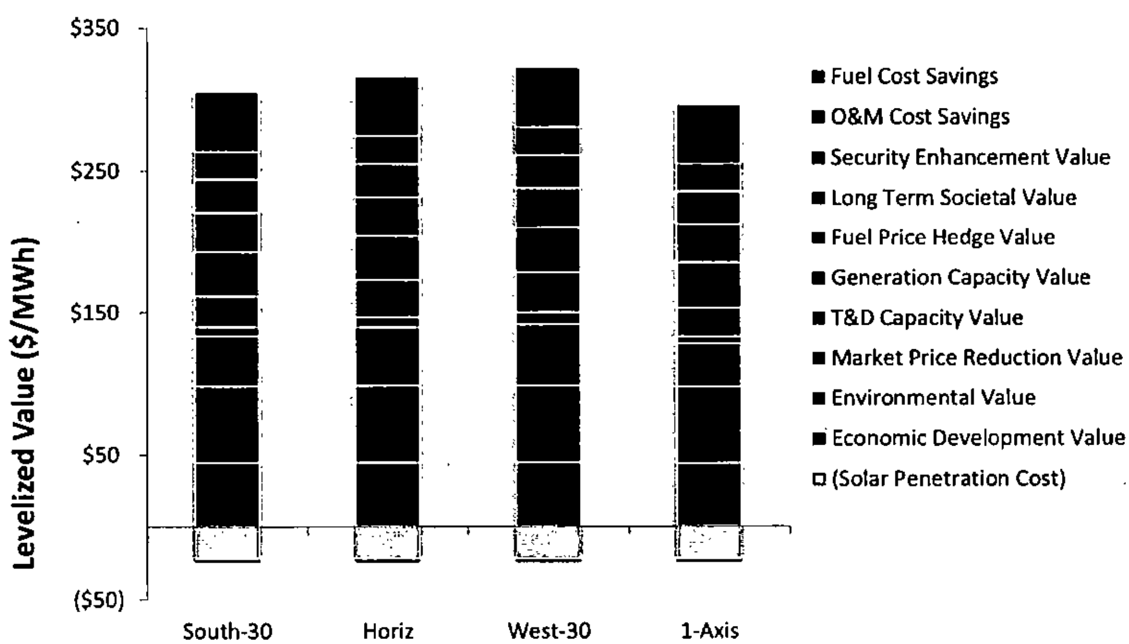


Figure A4- 2. Levelized Value ($/MWh), Pittsburgh.



Harrisburg

Table A4- 4. Technical results, Harrisburg.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	1129	1129	1129	1129
Annual Energy Production (MWh)	1,809,443	1,565,940	1,461,448	2,274,554
Capacity Factor (%)	18%	16%	15%	23%
Generation Capacity (% of Fleet Capacity)	28%	27%	26%	32%
T&D Capacity (% of Fleet Capaccity)	14%	14%	14%	14%

Table A4- 5. Value results ($/kW), Harrisburg.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$751	$652	$608	$942
O&M Cost Savings	$366	$318	$296	$459
Total Energy Value	$1,117	$969	$904	$1,401
Strategic				
Security Enhancement Value	$424	$368	$343	$532
Long Term Societal Value	$530	$460	$429	$665
Total Strategic Value	$954	$827	$772	$1,196
Other				
Fuel Price Hedge Value	$786	$682	$636	$985
Generation Capacity Value	$297	$287	$274	$336
T&D Capacity Value	$24	$24	$24	$24
Market Price Reduction Value	$1,241	$1,224	$1,171	$1,335
Environmental Value	$1,011	$877	$819	$1,268
Economic Development Value	$827	$717	$669	$1,037
(Solar Penetration Cost)	($424)	($368)	($343)	($532)
Total Other Value	$3,761	$3,444	$3,249	$4,454
Total Value	**$5,832**	**$5,240**	**$4,925**	**$7,051**

Table A4- 6. Levelized Value results ($/MWh), Harrisburg.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$41	$41	$41	$40
O&M Cost Savings	$20	$20	$20	$20
Total Energy Value	$60	$61	$60	$60
Strategic				
Security Enhancement Value	$23	$23	$23	$23
Long Term Societal Value	$29	$29	$29	$29
Total Strategic Value	$52	$52	$52	$51
Other				
Fuel Price Hedge Value	$42	$43	$43	$42
Generation Capacity Value	$16	$18	$18	$14
T&D Capacity Value	$1	$1	$2	$1
Market Price Reduction Value	$67	$76	$78	$57
Environmental Value	$55	$55	$55	$55
Economic Development Value	$45	$45	$45	$45
(Solar Penetration Cost)	($23)	($23)	($23)	($23)
Total Other Value	$203	$215	$217	$191
Total Value	**$315**	**$327**	**$330**	**$303**

Figure A4- 3. Value ($/kW), Harrisburg.

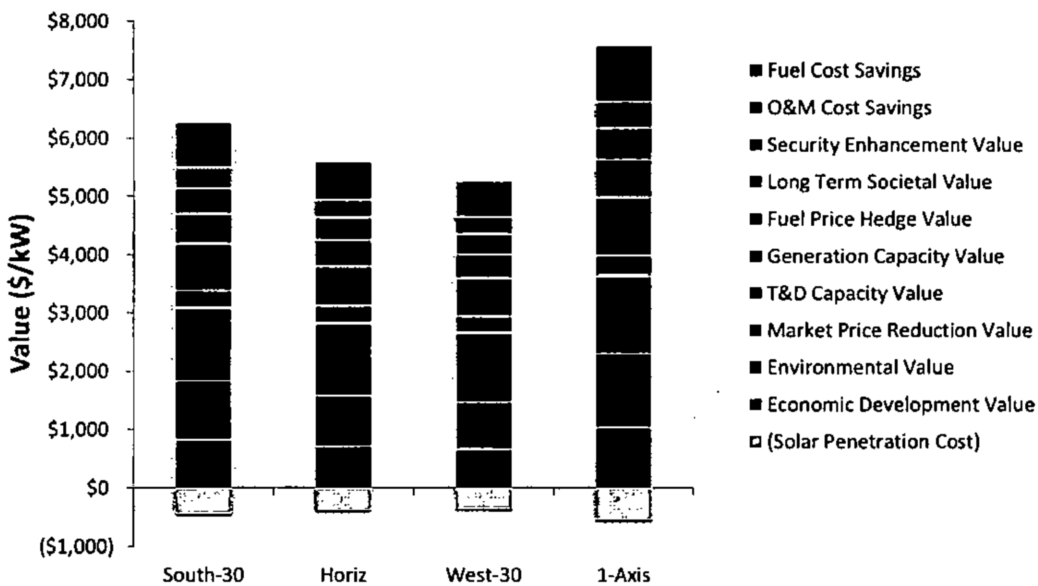
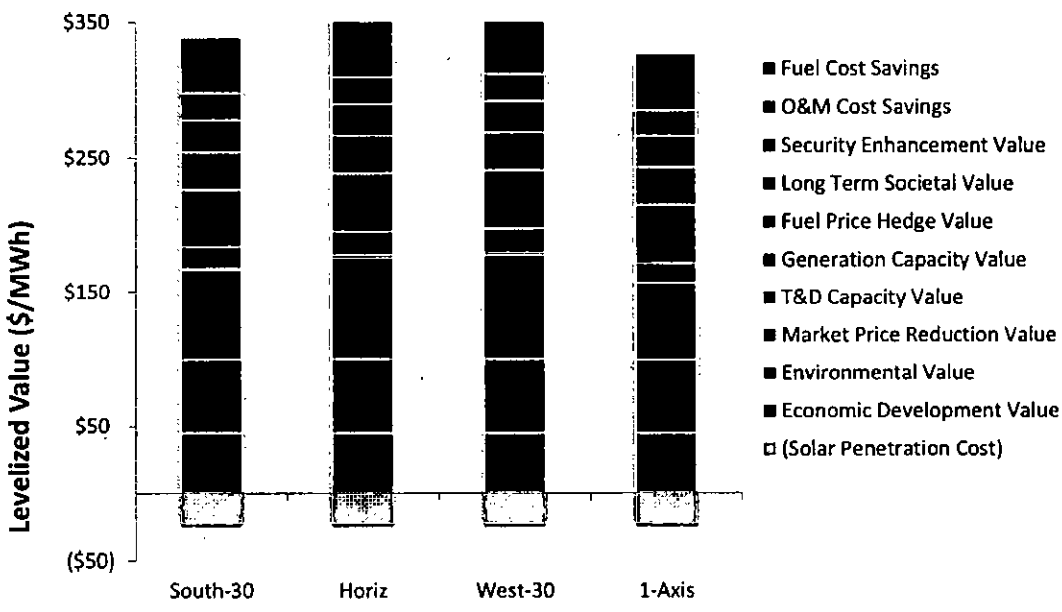


Figure A4- 4. Levelized Value ($/MWh), Harrisburg.



Scranton

Table A4- 7. Technical results, Scranton.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	1129	1129	1129	1129
Annual Energy Production (MWh)	1,698,897	1,479,261	1,386,699	2,123,833
Capacity Factor (%)	17%	15%	14%	21%
Generation Capacity (% of Fleet Capacity)	28%	27%	26%	32%
T&D Capacity (% of Fleet Capaccity)	14%	14%	14%	14%

Table A4- 8. Value ($/kW), Scranton.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$706	$616	$577	$880
O&M Cost Savings	$344	$300	$281	$429
Total Energy Value	$1,050	$916	$859	$1,309
Strategic				
Security Enhancement Value	$398	$348	$326	$497
Long Term Societal Value	$498	$435	$407	$621
Total Strategic Value	$896	$782	$733	$1,118
Other				
Fuel Price Hedge Value	$738	$644	$604	$921
Generation Capacity Value	$290	$283	$276	$336
T&D Capacity Value	$24	$24	$24	$24
Market Price Reduction Value	$1,206	$1,193	$1,157	$1,311
Environmental Value	$950	$829	$777	$1,185
Economic Development Value	$777	$678	$636	$969
(Solar Penetration Cost)	($398)	($348)	($326)	($497)
Total Other Value	$3,586	$3,303	$3,148	$4,249
Total Value	**$5,532**	**$5,001**	**$4,740**	**$6,676**

Table A4- 9. Levelized Value ($/MWh), Scranton.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$41	$41	$41	$41
O&M Cost Savings	$20	$20	$20	$20
Total Energy Value	$60	$61	$61	$60
Strategic				
Security Enhancement Value	$23	$23	$23	$23
Long Term Societal Value	$29	$29	$29	$29
Total Strategic Value	$52	$52	$52	$51
Other				
Fuel Price Hedge Value	$42	$43	$43	$42
Generation Capacity Value	$17	$19	$19	$15
T&D Capacity Value	$1	$2	$2	$1
Market Price Reduction Value	$69	$79	$82	$60
Environmental Value	$55	$55	$55	$55
Economic Development Value	$45	$45	$45	$45
(Solar Penetration Cost)	($23)	($23)	($23)	($23)
Total Other Value	$206	$218	$222	$196
Total Value	**$318**	**$331**	**$334**	**$307**

Figure A4- 5. Value ($/kW), Scranton.

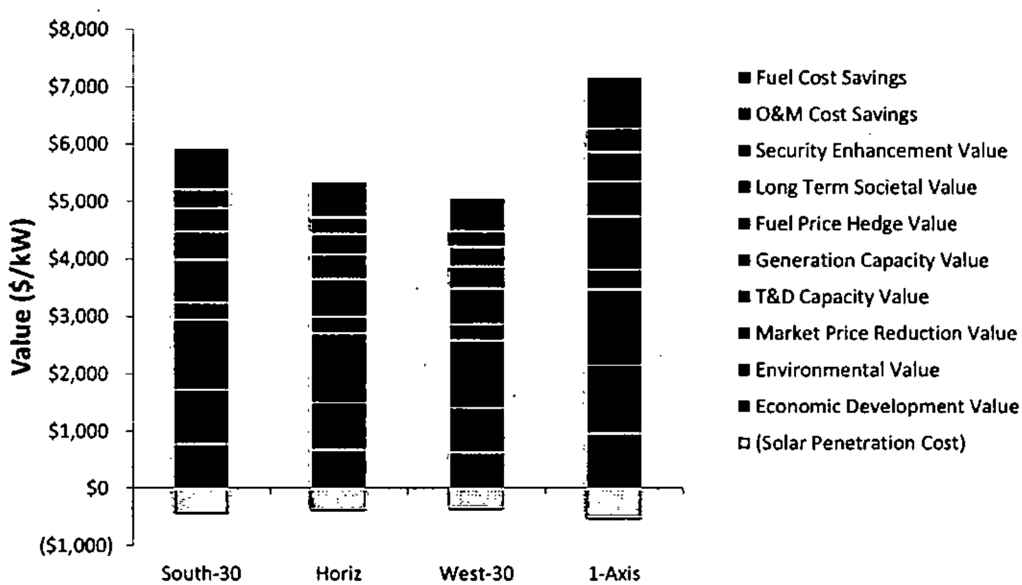
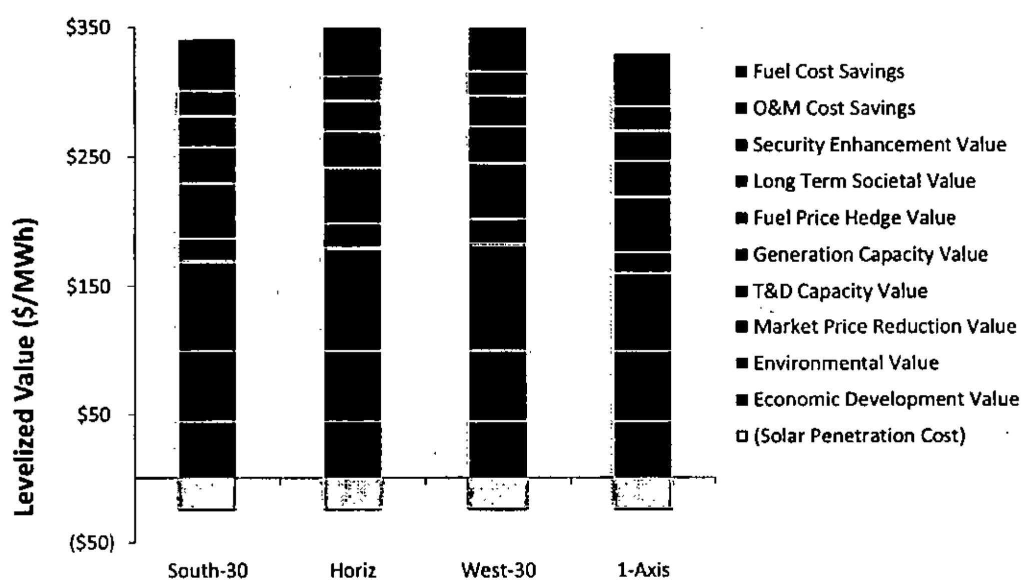


Figure A4- 6. Levelized Value ($/MWh), Scranton.



Philadelphia

Table A4- 10. Technical results, Philadelphia.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	1348	1348	1348	1348
Annual Energy Production (MWh)	2,339,424	1,991,109	1,847,394	2,943,101
Capacity Factor (%)	20%	17%	16%	25%
Generation Capacity (% of Fleet Capacity)	38%	40%	43%	46%
T&D Capacity (% of Fleet Capacity)	21%	21%	21%	21%

Table A4- 11. Value results ($/kW), Philadelphia.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$706	$602	$559	$886
O&M Cost Savings	$344	$294	$273	$432
Total Energy Value	$1,049	$896	$832	$1,318
Strategic				
Security Enhancement Value	$405	$346	$321	$509
Long Term Societal Value	$507	$432	$402	$636
Total Strategic Value	$912	$778	$723	$1,145
Other				
Fuel Price Hedge Value	$876	$747	$694	$1,100
Generation Capacity Value	$401	$418	$452	$483
T&D Capacity Value	$65	$65	$65	$65
Market Price Reduction Value	$1,013	$1,027	$1,018	$1,103
Environmental Value	$967	$825	$766	$1,214
Economic Development Value	$790	$675	$626	$993
(Solar Penetration Cost)	($405)	($346)	($321)	($509)
Total Other Value	$3,706	$3,412	$3,300	$4,449
Total Value	**$5,667**	**$5,086**	**$4,855**	**$6,912**

Table A4- 12. Levelized Value results ($/MWh), Philadelphia.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$38	$38	$38	$38
O&M Cost Savings	$18	$19	$19	$18
Total Energy Value	$56	$57	$57	$56
Strategic				
Security Enhancement Value	$22	$22	$22	$22
Long Term Societal Value	$27	$27	$27	$27
Total Strategic Value	$49	$49	$49	$49
Other				
Fuel Price Hedge Value	$47	$47	$47	$47
Generation Capacity Value	$22	$26	$31	$21
T&D Capacity Value	$3	$4	$4	$3
Market Price Reduction Value	$54	$65	$69	$47
Environmental Value	$52	$52	$52	$52
Economic Development Value	$42	$43	$43	$42
(Solar Penetration Cost)	($22)	($22)	($22)	($22)
Total Other Value	$199	$215	$224	$190
Total Value	**$304**	**$321**	**$330**	**$295**

Figure A4- 7. Value ($/kW), Philadelphia.

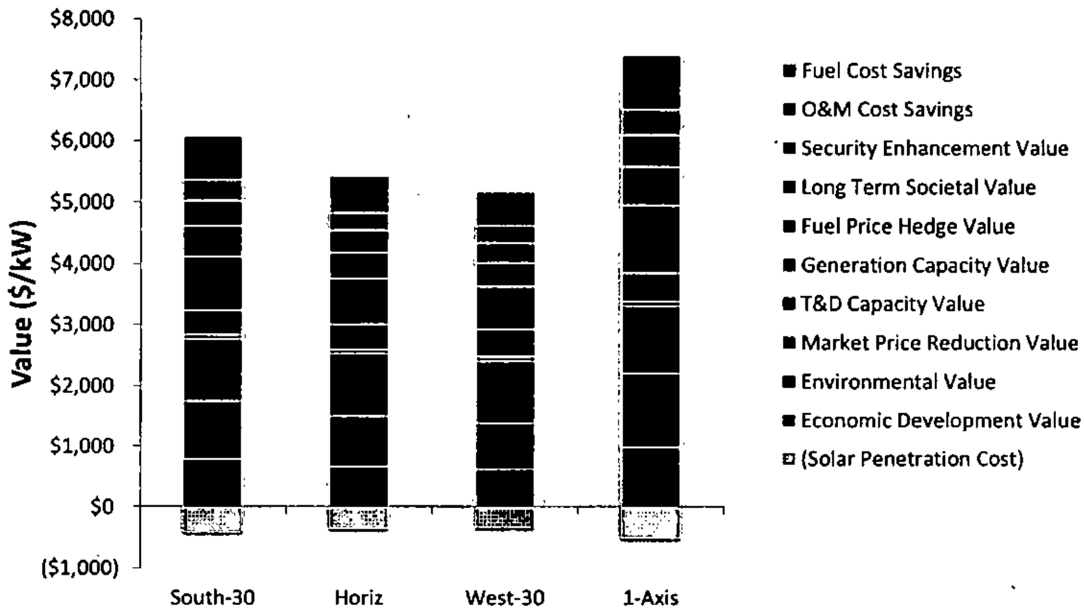
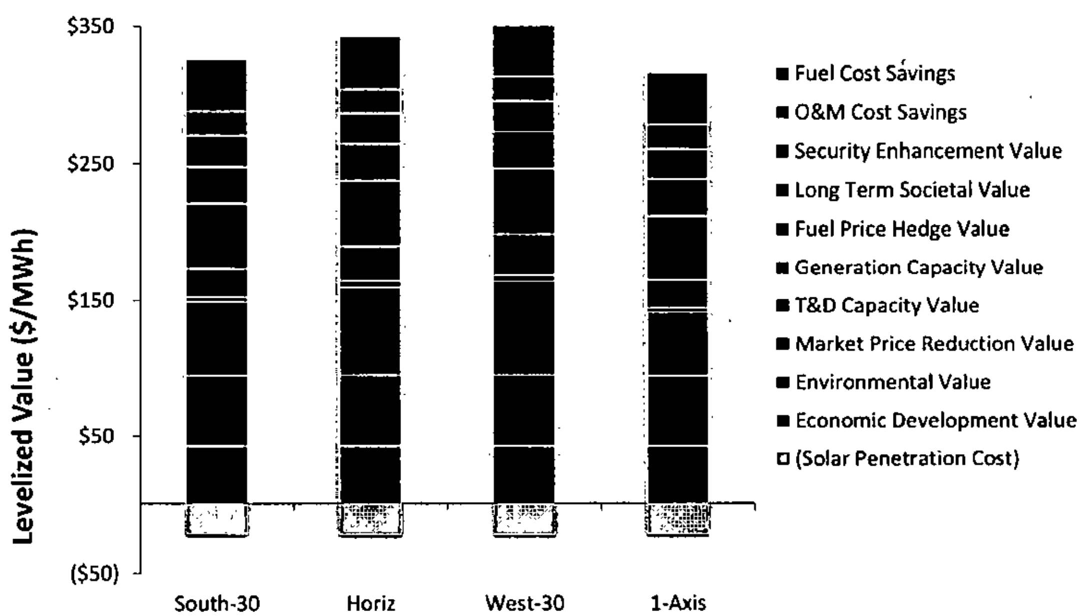


Figure A4- 8. Levelized Value ($/MWh), Philadelphia.



Jamesburg

Table A4- 13. Technical results, Jamesburg.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	991	991	991	991
Annual Energy Production (MWh)	1,675,189	1,431,899	1,315,032	2,102,499
Capacity Factor (%)	19%	16%	15%	24%
Generation Capacity (% of Fleet Capacity)	45%	47%	51%	52%
T&D Capacity (% of Fleet Capaccity)	29%	31%	29%	26%

Table A4- 14. Value results ($/kW), Jamesburg.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$1,020	$878	$808	$1,276
O&M Cost Savings	$497	$428	$394	$622
Total Energy Value	$1,517	$1,306	$1,203	$1,898
Strategic				
Security Enhancement Value	$549	$472	$435	$686
Long Term Societal Value	$686	$590	$544	$858
Total Strategic Value	$1,234	$1,062	$978	$1,544
Other				
Fuel Price Hedge Value	$586	$504	$465	$733
Generation Capacity Value	$468	$496	$531	$546
T&D Capacity Value	$23	$25	$23	$21
Market Price Reduction Value	$1,266	$1,306	$1,315	$1,363
Environmental Value	$560	$482	$444	$700
Economic Development Value	$1,097	$944	$870	$1,373
(Solar Penetration Cost)	($549)	($472)	($435)	($686)
Total Other Value	$3,451	$3,285	$3,212	$4,050
Total Value	**$6,202**	**$5,653**	**$5,393**	**$7,492**

Table A4- 15. Levelized Value results ($/MWh), Jamesburg.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$42	$42	$43	$42
O&M Cost Savings	$21	$21	$21	$21
Total Energy Value	$63	$63	$63	$63
Strategic				
Security Enhancement Value	$23	$23	$23	$23
Long Term Societal Value	$28	$29	$29	$28
Total Strategic Value	$51	$51	$52	$51
Other				
Fuel Price Hedge Value	$24	$24	$24	$24
Generation Capacity Value	$19	$24	$28	$18
T&D Capacity Value	$1	$1	$1	$1
Market Price Reduction Value	$52	$63	$69	$45
Environmental Value	$23	$23	$23	$23
Economic Development Value	$45	$46	$46	$45
(Solar Penetration Cost)	($23)	($23)	($23)	($23)
Total Other Value	$143	$159	$169	$134
Total Value	**$257**	**$274**	**$284**	**$247**

Figure A4- 9. Value ($/kW), Jamesburg.

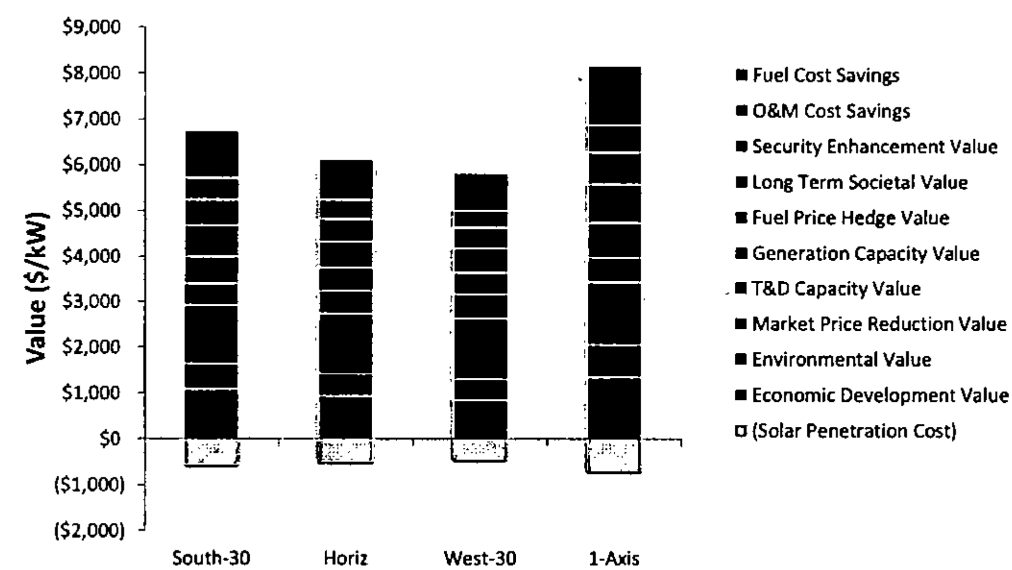
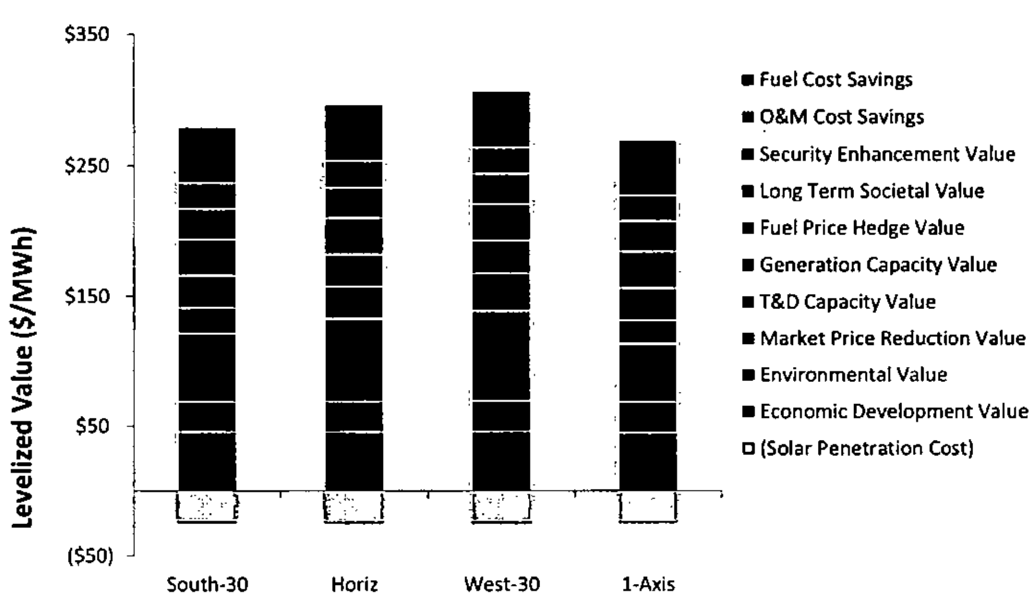


Figure A4- 10. Levelized Value ($/MWh), Jamesburg.



Newark

Table A4- 16. Technical results, Newark.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	1640	1640	1640	1640
Annual Energy Production (MWh)	2,677,626	2,303,173	2,118,149	3,350,313
Capacity Factor (%)	19%	16%	15%	23%
Generation Capacity (% of Fleet Capacity)	45%	47%	51%	54%
T&D Capacity (% of Fleet Capaccity)	56%	57%	57%	57%

Table A4- 17. Value results ($/kW), Newark.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$709	$612	$564	$885
O&M Cost Savings	$345	$298	$275	$431
Total Energy Value	$1,054	$911	$839	$1,317
Strategic				
Security Enhancement Value	$403	$348	$321	$503
Long Term Societal Value	$504	$435	$401	$629
Total Strategic Value	$907	$783	$721	$1,132
Other				
Fuel Price Hedge Value	$798	$689	$635	$996
Generation Capacity Value	$470	$489	$534	$568
T&D Capacity Value	$147	$151	$151	$151
Market Price Reduction Value	$927	$959	$958	$989
Environmental Value	$411	$355	$327	$513
Economic Development Value	$806	$696	$641	$1,007
(Solar Penetration Cost)	($403)	($348)	($321)	($503)
Total Other Value	$3,156	$2,991	$2,926	$3,721
Total Value	**$5,117**	**$4,685**	**$4,486**	**$6,170**

Table A4- 18. Levelized Value results ($/MWh), Newark.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$39	$39	$39	$39
O&M Cost Savings	$19	$19	$19	$19
Total Energy Value	$58	$58	$58	$58
Strategic				
Security Enhancement Value	$22	$22	$22	$22
Long Term Societal Value	$28	$28	$28	$28
Total Strategic Value	$50	$50	$50	$50
Other				
Fuel Price Hedge Value	$44	$44	$44	$44
Generation Capacity Value	$26	$31	$37	$25
T&D Capacity Value	$8	$10	$10	$7
Market Price Reduction Value	$51	$61	$66	$43
Environmental Value	$22	$23	$23	$22
Economic Development Value	$44	$44	$44	$44
(Solar Penetration Cost)	($22)	($22)	($22)	($22)
Total Other Value	$173	$190	$202	$163
Total Value	**$280**	**$298**	**$310**	**$270**

Figure A4- 11. Value ($/kW), Newark.

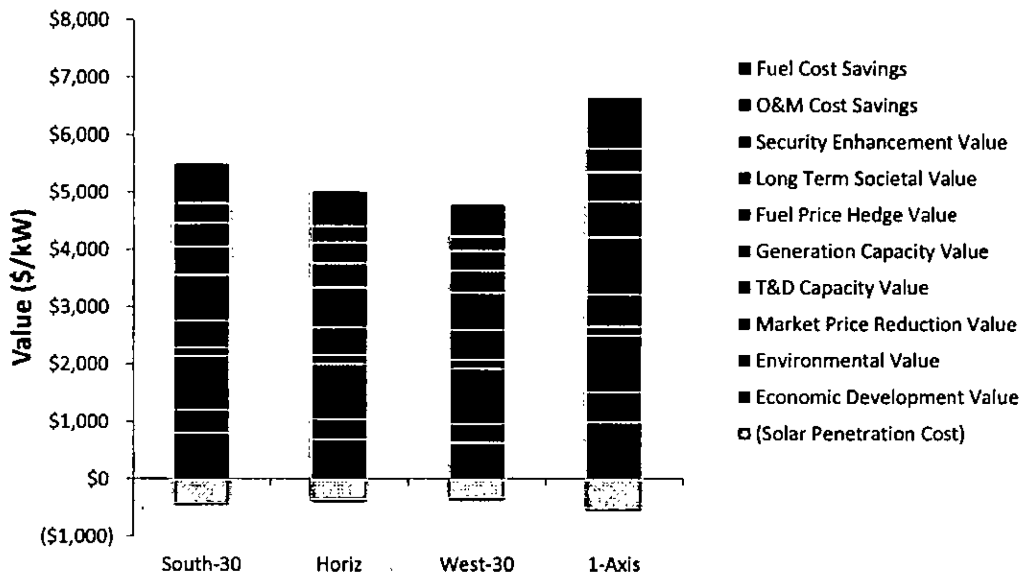
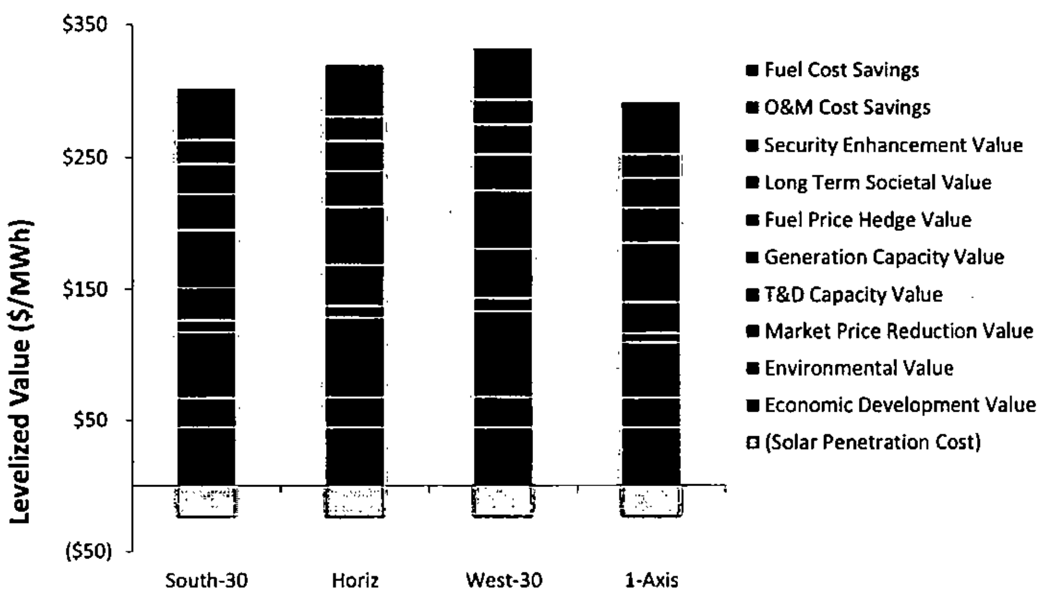


Figure A4- 12. Levelized Value ($/MWh), Newark.



Atlantic City

Table A4- 19. Technical results, Atlantic City.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	443	443	443	443
Annual Energy Production (MWh)	827,924	705,374	654,811	1,039,217
Capacity Factor (%)	21%	18%	17%	27%
Generation Capacity (% of Fleet Capacity)	46%	48%	54%	57%
T&D Capacity (% of Fleet Capaccity)	36%	37%	38%	36%

Table A4- 20. Value results ($/kW), Atlantic City.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$1,081	$927	$863	$1,354
O&M Cost Savings	$527	$452	$421	$660
Total Energy Value	$1,609	$1,380	$1,283	$2,015
Strategic				
Security Enhancement Value	$584	$501	$466	$732
Long Term Societal Value	$730	$626	$582	$914
Total Strategic Value	$1,314	$1,127	$1,048	$1,646
Other				
Fuel Price Hedge Value	$662	$567	$528	$828
Generation Capacity Value	$478	$503	$569	$600
T&D Capacity Value	$49	$51	$52	$49
Market Price Reduction Value	$1,412	$1,485	$1,508	$1,503
Environmental Value	$596	$511	$475	$746
Economic Development Value	$1,168	$1,002	$932	$1,463
(Solar Penetration Cost)	($584)	($501)	($466)	($732)
Total Other Value	$3,781	$3,618	$3,598	$4,458
Total Value	**$6,704**	**$6,125**	**$5,929**	**$8,119**

Table A4- 21. Levelized Value results ($/MWh), Atlantic City.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$41	$42	$42	$41
O&M Cost Savings	$20	$20	$20	$20
Total Energy Value	$61	$62	$62	$61
Strategic				
Security Enhancement Value	$22	$22	$22	$22
Long Term Societal Value	$28	$28	$28	$28
Total Strategic Value	$50	$50	$51	$50
Other				
Fuel Price Hedge Value	$25	$25	$25	$25
Generation Capacity Value	$18	$23	$27	$18
T&D Capacity Value	$2	$2	$2	$1
Market Price Reduction Value	$54	$66	$73	$46
Environmental Value	$23	$23	$23	$23
Economic Development Value	$45	$45	$45	$44
(Solar Penetration Cost)	($22)	($22)	($22)	($22)
Total Other Value	$144	$162	$174	$135
Total Value	**$256**	**$274**	**$286**	**$247**

Figure A4- 13. Value ($/kW), Atlantic City.

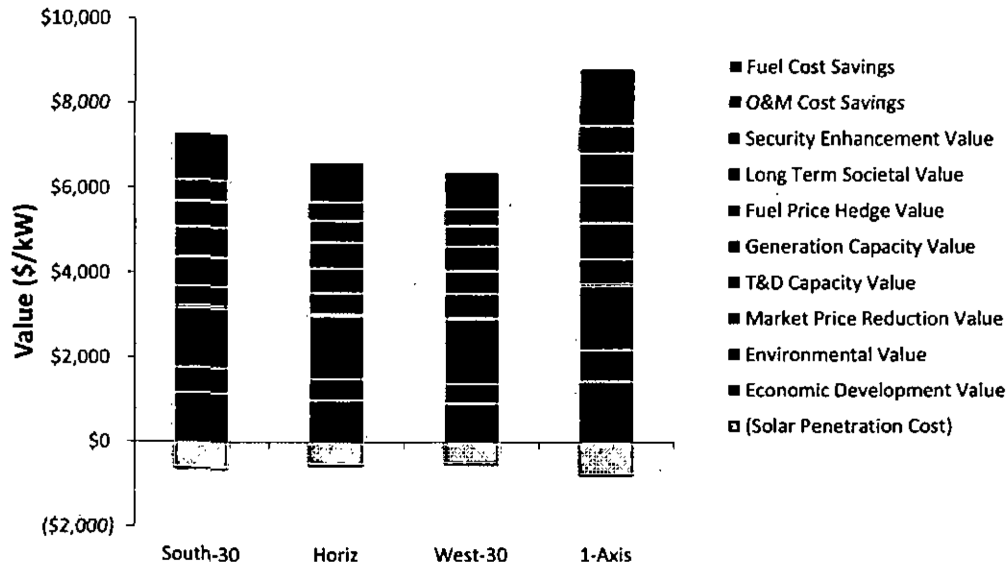
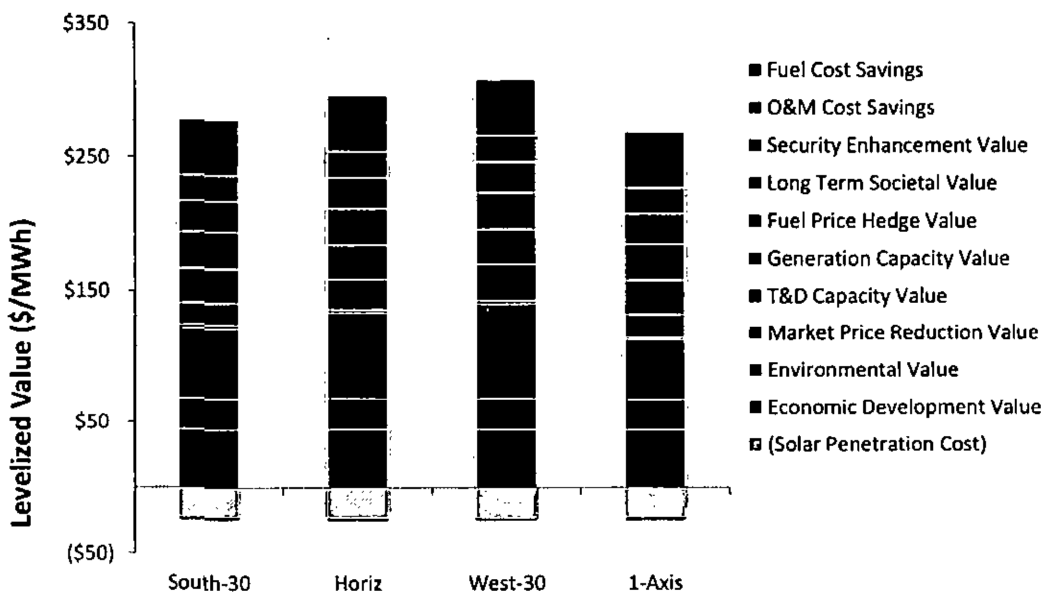


Figure A4- 14. Levelized Value ($/MWh), Atlantic City.



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BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

E-100 Sub 136

FILED

SEP 27 2013

Clerk's Office
N.C. Utilities Commission

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In the Matter of:

GEORGIA POWER COMPANY'S 2013 IRP and Application for Decertification of Plants Branch Units 3 and 4, Plant McManus Units 1 and 2, Plant Kraft Units 1 through 4, Plant Yates Units 1 through 5 and Plant Boulevard Units 2 and 3 : Docket No. 36498

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Hearing Room
Georgia Public Service Commission
244 Washington Street
Atlanta, Georgia

Tuesday, June 18, 2013

The above-entitled matter came on for hearing pursuant to Notice at 10:29 a.m.

BEFORE:

CHUCK EATON, Chairman
DOUG EVERETT, Vice Chairman
TIM G. ECHOLS, Commissioner
STAN WISE, Commissioner
LAUREN McDONALD, Commissioner

Brandenburg & Hasty
435 Cheek Road
Monroe, Georgia 30655

EXHIBIT

KRR-4

RENUMBERED as Staff Exhibits Number 54 through 67.)

CHAIRMAN EATON: Does that clear that all up?

COURT REPORTER: (Nods.)

CHAIRMAN EATON: All right. Georgia Power, you can swear in your panel.

MR. HEWITSON: Thank you, Mr. Chairman. Good morning.

At this time, I'd like to call Georgia Power's panel on rebuttal, Mr. Kyle Leach, Mr. Garey Rozier, Mr. Larry Legg and Ms. Alison Brown in Docket Number 36498, Georgia Power Company's 2013 integrated resource plan and application for decertification of Plants Branch units 3 and 4, Plant McManus units 1 and 2, Plant Kraft units 1 through 4, Plant Yates units 1 through 5, Plant Boulevard Units 2 and 3 and Plant Bowen unit 6.

Whereupon,

KYLE C. LEACH

GAREY C. ROZIER

LARRY T. LEGG

ALISON P. BROWN

appeared as witnesses herein and, having been first duly sworn, were examined and testified as follows:

DIRECT EXAMINATION

BY MR. HEWITSON:

But as we get down to who the winning bidders will be, that will give us an opportunity at that point to see if there's any issues there. We've made it very clear in the solicitation that we're -- that we're going to stick to the 20 per entity, and put limits on what an entity is, legal definition, those sorts of things.

It's just, I guess, on us to follow up on that and make sure that, as we award that, that --

VICE CHAIRMAN EVERETT: On an entity, make sure that the boards -- they have different boards and different directors and different owners.

WITNESS ROZIER: Those are the sorts of things that we would need to look at to make sure that we -- we met that obligation.

COMMISSIONER ECHOLS: I asked you earlier, Mr. Leach, about what your takeaway was from his witness's testimony, because it appeared that you -- you know, you had taken only a part -- as I listened to you, only the part that was -- you know, that would benefit the company and not the distributed generator.

So as he went through this laundry list of the seven benefits, I'm assuming that, because you said that the ASI plan was kind of built on the benefits, right, on the Austin plan?

WITNESS LEACH: We consulted the Austin plan as we were developing the components within the ASI.

COMMISSIONER ECHOLS: Yes.

WITNESS LEACH: I wouldn't say it was built entirely off of that, but we consulted it.

COMMISSIONER ECHOLS: All right. So let's just the 13 cents. Of benefit number one, on the -- say the energy benefit, the line loss savings, approximately how much of that 13 cent in the real -- the true value of solar that you say ASI has, is -- how much is the line loss savings? Is it a half a cent? A quarter of a cent? Is there -- what value would you assign to the line loss savings?

WITNESS LEACH: Well, the difference between the 12 cents that we're offering the utility scale, and the 13 cents that we're offering the distributed generation represents those T&D benefits. So avoided transmission, avoided distribution and avoided line loss.

COMMISSIONER ECHOLS: So about a penny?

WITNESS LEACH: So about a penny.

COMMISSIONER ECHOLS: Yeah. So if you went through all seven, which he was trying to get you, it sounds like, to acknowledge if two, three, four, five, six and seven had any kind of numerical value, but as you went through two through seven, I assume that you assigned some of those with numerical values as well in the ASI pricing?

WITNESS LEACH: No, sir. My response was that many of those benefits that Mr. Rabago pointed out in his testimony are things that are very difficult to quantify. And as I recall, you know, he talked about that if you take into consideration this full suite of benefits, and this is not to say that the city of Austin did. But you could see, if I recall correctly, values of 45 cents a kilowatt hour.

When you take into account some of the physical tangible benefits that solar distributed generation provides and then you layer in on top of it some of these other less tangible and less quantifiable benefits. And so -- and then the -- I think he adjusted it down to maybe 25 cents a kilowatt hour. But ultimately, the viewpoint of the city of Austin's program -- my interpretation is -- as a utility that's doing it the right way.

And so my point was, is the company's ASI program includes many of the same components of it. It doesn't include some of these very difficult to quantify benefits, and I think some of the benefits are arguable. Different people can look at it and determine whether that's a benefit or not, or if that's a benefit that this resource deserves and this resource does not.

But my point was, and my apologies if I didn't make it clearly enough, is that we thoroughly agree that there is a valuation of solar, there is a value of solar.

We believe that we have properly accounted for that in ASI. It certainly has been a very robust review process as we've developed that pricing, with a lot of input from Commission staff as well as input from the solar community. And so we feel that's a good, accurate understanding of the value solar brings, and we're paying that under ASI.

On the flip side is -- and I think Mr. Rabago agreed -- is that there are benefits that the customer receives from the utility that should be fairly paid for also. And so maybe I asserted too much on the utility side, but that's not to undermine at all our view that resources should get the proper compensation of what they bring to the grid.

COMMISSIONER ECHOLS: It may just mean that on item four or item six, it just needs more analysis. That at first glance you -- you were having a hard time quantifying. But given further discussion and further analysis from the minds at Georgia Power and outside people contributing to this, you might be able to quantify it, or come up with your best guess.

WITNESS LEACH: Commissioner, we'll take a look at it, certainly. I mean, we would need to be able to demonstrate to this Commission that those are tangible benefits that all customers are receiving by the company purchasing these resources. And you know, the company's willing to take a look at it and see if there is a way. If we agree that those are benefits that solar's providing, that our customers are benefiting from that, then as a --

COMMISSIONER ECHOLS: As he was reading them off, it sounded from your reaction like you hadn't heard these before, or that you hadn't looked closely at these.

WITNESS LEACH: No, sir.

COMMISSIONER ECHOLS: I just wondered how much you actually did study these benefits and consider them.

WITNESS LEACH: Well, I -- what we did is we studied the city of Austin program. We looked at other types of programs, too, and we --

COMMISSIONER ECHOLS: In general?

WITNESS LEACH: In general. I can't say that we specifically drilled down and did exhaustive analysis on some of these other benefits, too. I'm just pointing out a general observation of those and the challenge of quantifying them.

WITNESS ROZIER: And there are also some hard to quantify disbenefits of solar resources that, you know, we know they're there, but it's very hard to quantify. For instance, we pay this fixed price schedule every hour that we get the energy, regardless of whether it's more expensive or less expensive than our system cost. It's not controllable like another resource would be that's regulated and those sorts of things.

So there -- you know, there are things on both sides of the pendulum there.

COMMISSIONER ECHOLS: Thank you.

BY MR. GALLOWAY:

Q Let me follow up briefly and then I'll conclude on Commissioner Echols' questions.

Bottom line, if we value solar properly and contracts are based and let on that valuation, then there should be no upward pressure on rates from solar deployment because the cost is equaling its value?

A (Witness Leach) I would agree. If we value -- the key phrase is valuing it properly.

Q And we would fight over what the value is. That would be the prospective potential fight, what -- how do we calculate the value and what is it?

A (Witness Leach) That would be certainly up for debate.

Q Okay. And so as we -- as we end this -- as we end the rebuttal phase, there's room and opportunity to expand solar based on energy benefit if we can get it valued correctly, and it's up to the Commission as to the amount and timing?

A (Witness Leach) That's what we said in our testimony.

E-100 Sub 136

PROGRESS ENERGY, INC.

Interrogatory:

The Commission's Order Approving Fuel Charge Adjustment in Docket No. E-2, Sub 1001, indicates on page 15 that "[t]he impact of hedge settlements increased the cost of natural gas for North Carolina retail customers during the test period by approximately $39 million." Please describe the impact of hedge settlements on the cost of natural gas for North Carolina retail customers during the test period in this case.

Response:

The impact of natural gas hedge settlements for North Carolina customers during the test period was additional cost of $50,840,318. The impact increased cost due to declining market prices as compared to prices in effect at the time of hedge origination. NC Retail customers fully participated in the benefit of the effect of declining natural gas market prices for the 51% of PEC's natural gas consumption that was not hedged.

EXHIBIT
KRR-5

DUKE ENERGY PROGRESS

Request:

The Commission's Order Approving Fuel Charge Adjustment in Docket No. E-2, Sub 1001, indicates on page 15 that "[t]he impact of hedge settlements increased the cost of natural gas for North Carolina retail customers during the [2010] test period by approximately $39 million."

In response to an NCSEA data request in Docket No. E-2, Sub 1018, DEP (then PEC) stated: "The impact of natural gas hedge settlements for North Carolina customers during the [2011] test period was additional cost of $50,840,318. The impact increased cost due to declining market prices as compared to prices in effect at the time of hedge origination. NC Retail customers fully participated in the benefit of the effect of declining natural gas market prices for the 51% of PEC's natural gas consumption that was not hedged."

Please describe the impact of hedge settlements on the cost of natural gas for North Carolina retail customers during the test period in this case.

Response:

The impact of natural gas hedge settlements for NC Retail Customers during the test period April 2012 to March 2013 was approximately $70 million dollars. The impact increased cost due to declining market prices as compared to prices in effect at the time of hedge origination. NC Retail customers fully participated in the benefit of the effect of declining natural gas market prices for the 52% of DEP's natural gas consumption that was not hedged.

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PLACE: Dobbs Building, Raleigh, North Carolina

DATE: June 4, 2013

DOCKET NO.: E-7, Sub 1033

TIME IN SESSION: 9:30 A.M. TO 10:09 A.M.

BEFORE: Chairman Edward S. Finley, Jr., Presiding

Commissioner William T. Culpepper, III

Commissioner Bryan E. Beatty

Commissioner ToNola D. Brown-Bland

Commissioner Lucy T. Allen

IN THE MATTER OF:

Duke Energy Carolinas, LLC.

Application of Duke Energy Carolinas, LLC

Pursuant to G.S. 62-133.2 and NCUC Rule R8-55

Relating to Fuel and Fuel-Related Charge

Adjustments for Electric Utilities.

VOLUME 1

Q. HOW IS NATURAL GAS DELIVERED TO THE COMPANY'S GENERATING FACILITIES?

A. The Company procures long-term firm transportation that provides natural gas to its generating facilities. In addition, as needed, the Company may procure shorter-term firm pipeline capacity through the capacity release market and market supply options that provide the needed natural gas supply to its generating facilities.

Q. DOES DEC MAINTAIN AN INVENTORY OF NATURAL GAS?

A. The Company does not have an agreement for storage capacity, nor does it maintain an inventory of natural gas. Progress Energy Carolinas, however, does have a storage agreement which was released to DEC as part of the AMA. As the Asset Manager, DEC will procure all the needed supply for the combined Carolinas gas needs and as part of that agreement, will have access to the released storage agreement. On any given day, DEC may utilize the storage to balance and support the Carolinas gas needs.

Q. WHAT CHANGES IN VOLUME DOES THE COMPANY ANTICIPATE WITH NATURAL GAS CONSUMPTION?

A. The Company's natural gas consumption is expected to continue to increase. The Company consumed approximately 42 billion cubic feet ("Bcf") of natural gas in 2012, compared to approximately 10 Bcf in 2011. This increase was driven by the downward trend in the natural gas prices as well as the operation of the Buck CC facility for its first full year ending on December 31, 2012. For 2013, DEC's current forecasted natural gas consumption is approximately 74

Bcf. This forecast is based on current natural gas prices which are forecasted to remain low, as noted later in my testimony, and includes a full year of operations of Dan River CC, which went into commercial service in December 2012

Q. **PLEASE DESCRIBE THE CURRENT STATE OF THE NATURAL GAS MARKET, INCLUDING THE NATURAL GAS PRICES EXPERIENCED DURING THE TEST PERIOD.**

A. The development of shale gas has created a fundamental shift in the nation's natural gas market. Shale gas is natural gas that is trapped within shale formations, and which can provide an abundant source of petroleum and natural gas. Within recent years, improvements in production technologies have allowed greater access to the natural gas trapped in these formations, and has resulted in increased reserves that can produce natural gas supply more quickly and economically. Given continued production increases, natural gas prices continue to remain at lower levels. The Company's average price of gas purchased for calendar year 2012 was $3.34 per Million British Thermal Units ("MMBtu"), compared to $4.85 per MMBtu in 2011.

Q. **PLEASE DESCRIBE THE OUTLOOK FOR THE NATURAL GAS MARKET, INCLUDING THE EXPECTED NATURAL GAS PRICE TREND FOR THE BILLING PERIOD.**

A. New production from shale gas has contributed to substantial increases in the supply of U.S. marketed natural gas. This increase has outstripped demand growth. The Company expects the shale gas production percentage of total natural gas domestic production to continue to increase over time. The current

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1031

In the Matter of	)	
Application of Duke Energy Progress, Inc.	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**SASHA J. WEINTRAUB FOR**
R8-55 Relating to Fuel and Fuel-Related	)	**DUKE ENERGY PROGRESS, INC.**
Charge Adjustments for Electric Utilities	)	

Q. WHAT CHANGES IN VOLUME DOES THE COMPANY ANTICIPATE WITH NATURAL GAS CONSUMPTION?

A. The Company's natural gas consumption is expected to continue to increase. The Company consumed approximately 91 billion cubic feet ("Bcf") of natural gas in the test period, compared to approximately 72 Bcf in the prior test period. This increase was driven by the downward trend in the natural gas prices as well as the operation of the second CC power block at the Richmond facilities. For the billing period, DEP's current forecasted natural gas consumption is approximately 158 Bcf. This forecast is based on current natural gas prices which are forecasted to remain low.

Q. PLEASE DESCRIBE THE CURRENT STATE OF THE NATURAL GAS MARKET, INCLUDING THE NATURAL GAS PRICES EXPERIENCED DURING THE TEST PERIOD.

A. The development of shale gas has created a fundamental shift in the nation's natural gas market. Shale gas is natural gas that is trapped within shale formations, and which can provide an abundant source of petroleum and natural gas. Within recent years, improvements in production technologies have allowed greater access to the natural gas trapped in these formations, and has resulted in increased reserves that can produce natural gas supply more quickly and economically. Given continued production increases, natural gas prices continue to remain at lower levels. The Company's average price of gas purchased for the test period was $5.11 per Million British Thermal Units ("MMBtu"), compared to $5.49 per MMBtu during the prior test period.

DUKE ENERGY CAROLINAS AND DUKE ENERGY PROGRESS

Request:

Please explain how DEC and PEC (now DEP) accounted for (a) any avoided transmission and distribution costs associated with distributed solar or wind facilities, and/or (b) any avoided line losses associated with distributed solar or wind facilities. To the extent quantifiable, please explain the portion (in cents/kWh) of each company's proposed overall 15-year fixed avoided cost rate that is attributable to any avoided T&D costs or avoided line losses.

(a) Provide any reports (or explain where any public reports can be found) prepared by or for DEC or PEC (now DEP) that estimate transmission and distribution system energy losses in relation to load, including line loss factor used to set retail rates.

DEC Response:

DEC did not include transmission and distribution costs associated with distributed solar or wind in its proposed avoided costs and also did not specifically identify any avoided line losses associated with distributed solar or wind facilities. The calculation of avoided line losses includes all facilities on the system and does not distinguish solar distributed facilities separately. The elimination of avoided line losses, including the Step Up Transformer losses, would result in annualized 15 year Option B rate, connected to the distribution system from an annualized rate of 5.8 to 5.66. For the annualized 15 year Option B rate, connected to the transmission system the rate would drop from an annualized rate of 5.67 to 5.66.

DEP Response (if different):

DEP did not include any avoided transmission and distribution costs or any avoided line losses associated with distributed solar or wind facilities in its avoided cost rates filed under CSP-29. DEP did include a value for estimated avoided line losses over the transmission system within the avoided capacity and energy rates for qualifying facilities that deliver power into DEP's distribution system. These line losses were estimated at on- peak and off- peak hours, and account for 0.05 – 0.11 cents/kWh difference in energy and capacity rates for a 15 year contract delivering power into its distribution vs. transmission systems.

EXHIBIT
KRR-6