PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

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Annual Review of Base Rates for Fuel Costs for Duke Energy Progress, LLC	}	**Docket No. 2018-1-E**
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Direct Testimony of
Devi Glick

On Behalf of
South Carolina Coastal Conservation League and Southern Alliance for Clean Energy

On the Topic of
Annual Review of Base Rates for Fuel Costs for Duke Energy Progress, LLC

May 22, 2018

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address for the record.

A. My name is Devi Glick. I work at Synapse Energy Economics, Inc., located at 485 Massachusetts Avenue in Cambridge, Massachusetts.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and natural gas industry regulation, planning, and analysis. Our work covers a range of issues, including integrated resource planning; economic and technical assessments of energy resources; electricity market modeling and assessment; energy efficiency policies and programs; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, the U.S. Department of Energy, the U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 20 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan; a bachelor's degree in environmental studies from Middlebury College; and more than five years of professional experience as a consultant, researcher, and analyst.

At Synapse and previously at Rocky Mountain Institute, I have focused on a wide range of energy and electricity issues, including: utility resource planning, distributed energy resource valuation, energy efficiency program impact analysis, and rate design effectiveness. For this work, I develop in-house models and perform analysis using industry-standard models.

On topics related to the costs and benefits of distributed generation, I have co-authored two studies reviewing valuation methodologies for solar photovoltaics (PV). These studies have been highly cited in public utility proceedings for their recommendations around distributed energy resource pricing and rate design. Most recently, I evaluated various rate design options for distributed energy resources within the state of Hawaii.

My CV is attached as Exhibit DG-1.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the South Carolina Coastal Conservation League (CCL) and Southern Alliance for Clean Energy (SACE).

Q. Have you testified previously before the South Carolina Public Service Commission ("the Commission")?

A. Yes. I testified on behalf of CCL and SACE in South Carolina Electric & Gas Company's most recent annual fuel cost proceeding, Commission Docket Number 2018-2-E.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my testimony is to provide input on the 2018 application of the Net Energy Metering (NEM) Methodology for valuing distributed energy resources (DERs) on Duke Energy Progress, LLC's (DEP or the Company) system within South Carolina. DEP includes zero values for most of the NEM Methodology calculations for 2018. My testimony is narrowly focused on providing input on how to proceed with filling in several of these components within the NEM Methodology. Note that the fact that I have not addressed each of the zero value components does not mean that I agree that zero is the appropriate value.

Q. How is the remainder of your testimony organized?

A. My testimony is organized as follows:

1. Introduction and Qualifications
2. Summary of Conclusions and Recommendations
3. Background on the NEM and Fuel Cost Calculations
4. Net Energy Metering Methodology – 2018 Application

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

- DG-1: Resume of Devi Glick,
- DG-2: Report from the Rocky Mountain Institute: *A Review of Solar PV Benefit and Cost Studies*,
- DG-3: The Mendota Group, LLC. *Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments, for Public Service Company of Colorado*, and
- DG-4: Avoided Transmission Capacity Calculation.

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions.

A. My primary conclusions, discussed and supported in greater detail below, are summarized as follows:

1. It is possible to quantify avoided transmission costs and those avoided costs are non-zero, therefore DEP should no longer be permitted to use a placeholder value of zero in the transmission and distribution (T&D) capacity category.
2. It is possible to quantify the avoided environmental cost of coal ash disposal as it relates to distributed PV, therefore DEP should no longer be

permitted to use a placeholder value of zero in the Environmental Costs category.

3. An updated line losses study that calculates the distributed PV output-weighted marginal line loss based on the current footprint of DEP would improve application of the NEM methodology.

Q. Please summarize your primary recommendations.

1. The Commission should require DEP to immediately adopt an avoided T&D Capacity value of $0.005778/kWh based on the Current Values approach described below.
2. DEP should conduct a study to more specifically quantify the avoided environmental cost of coal ash disposal as it relates to distributed PV to inform future NEM valuation updates in the fuel cost proceedings.
3. DEP should perform an updated line losses study to quantify marginal line losses associated with avoided energy, generating capacity and transmission capacity costs across DEP's current footprint. This study should be based on the Company's forecasted load and generation, and it should use a solar PV profile (not a fixed constant output profile).

3. BACKGROUND ON THE NEM AND FUEL COST CALCULATIONS

Q. Did DEP correctly calculate the value for each component of NEM distributed energy resource?

A. No, DEP did not. DEP assigned a value of zero to seven of the eleven components of NEM without presenting a detailed analysis of several components, including transmission and distribution cost deferral and avoided environmental costs.

Q. Is DEP required to calculate a value for each NEM component or can it continue to use a value of zero as a placeholder?

A. DEP must calculate values for several components that it has previously valued at zero. In the 2014 Settlement Agreement to Docket No. 2014-246-E, the parties agreed that:

> "The Methodology includes all categories of potential costs of benefits to the Utility system that are capable of quantification or possible quantification in the future. Where there is currently a lack of capability to accurately quantify a particular category and/or a lack of cost of benefit to the Utility system the category has been included in the Methodology as a placeholder … **Placeholder categories will be updated and included in the calculation of costs and benefits of net metering if and when capabilities to reasonably quantify those values and quantifiable costs or benefits to the Utility system in such categories become available."**

There exists currently the capability to quantify the value of Transmission and Distribution Capacity deferral, and avoided environmental costs, therefore DEP is required to calculate these costs and include them in the value of NEM.

4. NET ENERGY METERING METHODOLOGY – 2018 APPLICATION

Transmission and Distribution Capacity Costs

Q. How has DEP presented the value associated with avoided Transmission and Distribution Capacity Costs?

A. DEP included the value as $0.00000 (Witness Brown Testimony, page 8, table 4) for avoided transmission and distribution (T&D) capacity, for both Small and Large PV.

Q. Is a zero value appropriate for the avoided Transmission and Distribution Capacity cost component?

A. No. A value of zero was initially used as a placeholder because a detailed transmission and distribution avoided cost study could not be completed quickly enough for inclusion in the first docket. It is not clear from DEP testimony that the Company has attempted to calculate or quantify this component. It is now possible to reasonably quantify the avoided transmission and distribution capacity costs, therefore there is no longer adequate justification to use a placeholder value.

Q. Have other utilities adopted a non-zero value for avoided Transmission and Distribution Capacity cost component?

Yes. In 2013 I reviewed 15 studies for Rocky Mountain Institute's "A Review of Solar PV Benefits & Costs Studies, 2nd Edition."[1] This study was included in the set of materials provided at "The World after Act 236" Continuing Legal Education Conference presented by The Electric Cooperatives of South Carolina and South Carolina Coastal Conservation League, August 25-26, 2014 at Wild Dunes Resort, Isle of Palms, SC. A copy of this study is attached as Exhibit DG-2.

Twelve of the reviewed studies included a Transmission and Distribution benefit within the avoided cost categories. All 12 included a non-zero avoided cost for the Transmission and Distribution benefit. For example, Crossborder Energy found an avoided Transmission and Distribution capacity value of around $0.025/kWh for Arizona Public Service and $0.015/kWh for California. Since that time, many more value of solar studies have been conducted and had a non-zero value for avoided transmission or distribution capacity.

Q. What approaches have other utilities taken to calculate the value of avoided transmission and distribution capacity costs?

A. Utilities have taken several different approaches to valuing avoided transmission and avoided distribution costs. Below is a sample of methodologies that utilities

[1] Hansen, L, Lacy, V, and Glick, D. 2013. *A Review of Solar PV Benefit and Cost Studies.* Rocky Mountain Institute. Available at https://rmi.org/wp-content/uploads/2017/05/RMI_Document_Repository_Public-Reprts_eLab-DER-Benefit-Cost-Deck_2nd_Edition131015.pdf

have used to quantify the value of avoided transmission or avoided distribution costs:

Maine's Value of Solar study, Clean Power Research (CPR)

For this study, CPR used historical transmission tariffs as a proxy for the cost of future transmission that is avoidable or deferrable through the use of distributed generation (DG). Maine is part of ISO-New England, and pays a transmission tariff (ISO-NE Open Access Transmission Tariff (OATT)) on a per-KW demand charge that is a function of monthly system peak for transmission service. "Avoided costs are estimated by determining the savings to the distribution utility that would result from a reduction of monthly peak demands and the resulting reduction in network load allocation."[2]

MidAmerican Energy Company, Demand Side Management Filings

MidAmerican took a simplified Current Values approach. It calculated the average cost to serve existing load by dividing both the transmission and distribution system net cost by the systems peak capability. MidAmerican used publicly available FERC Form 1 data on original cost of plant less accumulated depreciation, load data and generation capability data to estimate the $/kW cost for each system.[3]

PacifiCorp IRPs

PacifiCorp used a cost of service study to estimate the value of avoided transmission and distribution credits for its Integrated Resource Plan (IRP) in Oregon, Washington, Idaho, California, Wyoming, and Utah. PacifiCorp estimated the demand-related substation costs by looking at substation capacity investment for the next five years, dividing that investment by total increased capacity in kVA, and annualizing the result. PacifiCorp did the same for

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[2] Clean Power Research, *Maine Public Utilities Commission, Distributed Solar Valuation Study*. April, 2015.

[3] "Direct Testimony of Jennifer L. Long," Application for Approval of Energy Efficiency Plan for 2014-2018 (Docket EEP-2012-0002), Submitted to Iowa Public Utilities Board by MidAmerican Energy Company, Feb. 1, 2013, p. 4. Note that MidAmerican modified its approach to incorporate on peak load data instead of generation capability data.

transmission costs, dividing total growth-related transmission investment over the next five years by forecasted change in peak, and annualizing the result.[4]

Q. What approaches should DEP consider? Please explain each in detail, including the advantages and disadvantages of each.

A. There are several potential approaches that DEP can take. It is important to note that even though avoided T&D capacity is expressed as a single component, it is composed of two distinct components, transmission capacity and distribution capacity, and these can be evaluated and calculated separately.

<u>System Planning Study</u>

DEP could do a systems planning study that takes an in-depth forward-look at the utility's forecasted load, transmission and distribution plans.[5] For both the transmission and distribution systems, the utility would model the respective system (distribution or transmission) with and without incremental blocks of distributed solar PV (or alternatively with decreased load). DEP could then compare the present value of the original transmission and distribution investment plan and the deferred or avoided transmission and distribution investments. This approach is the most accurate, but also the most time intensive and costly to conduct. It also requires full information on the company's transmission and distribution systems, generators and load, as well as modeling software that is capable of representing system operation and capacity expansion.

<u>Review of Historical Transmission and Distribution Spending</u>

Absent a full system plan, DEP can review prior transmission and distribution spending and identify which projects were deferrable due to solar PV.[6] A retrospective review of prior spending requires access to, and knowledge of all

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[4] The Mendota Group, LLC. *Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments, for Public Service Company of Colorado*. October, 2014, pages 8-9.

[5] The Mendota Group, LLC. *Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments, for Public Service Company of Colorado*. October, 2014, page 6.

[6] The Mendota Group, LLC. *Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments, for Public Service Company of Colorado*. October, 2014, page 8.

projects and spending on either the transmission or distribution system over a period of years sufficient to display normal investment. Investments would be broken down into two categories: upgrades required due to load growth, and upgrades not related to load growth. Upgrades required to meet load growth could be considered avoidable. This approach is less accurate than a full in-depth model and still requires full access to the Company's T&D plans and a technical understanding of which types of projects are driven by load growth and which are not.

Statistical Correlation of Transmission and Distribution Capital Investment and Forecasted Load Growth

DEP can estimate the avoided cost of T&D based on statistical analysis of the correlation between transmission and distribution spending and forecasted load growth. This approach evaluates how much transmission or distribution spending can be deferred or avoided by solar PV, and how much spending is independent of load growth and is not impacted by solar PV. This methodology is less accurate than the in-depth study and the retrospective review, but only requires utility data on T&D investment broken down by the year in which projects came online. Estimates can be performed with publicly available forecasts on load growth and FERC Form 1 data on transmission spending when detailed utility data is not provided.

Current Values Approach

The Current Values approach uses publicly available data on T&D system investments to calculate an average avoided cost. Specifically, FERC Form 1 data on original cost of plant less accumulated depreciation is divided by peak system capability to provide the $/kW cost for each system.

Q. Have you calculated a value for avoided T&D on DEP's system? If yes, which approach did you use?

A. Yes, I have. I used the Current Values approach to estimate which transmission and distribution spending was correlated with load growth and could be deferred or avoided through distributed PV. Despite multiple discovery requests, access to more detailed T&D spending reports or information was not provided in time for this testimony deadline, and therefore I was not able to conduct more in-depth analysis on transmission and distribution spending.[7]

Q. How would you recommend the Commission proceed with respect to determining a company- and state-specific avoided T&D component value?

A. If DEP's system is summer peaking, the avoided transmission capacity value is $0.050851/kWh (Exhibit DG-4, Row 10). If, on the other hand, DEP's system is dual peaking, the avoided transmission capacity value is the smaller of the two seasonal values, $0.005778/kWh (Exhibit DG-4, Row 11). Because DEP currently purports to be dual peaking, I recommend that the Commission immediately adopt the duel peaking value of $0.005778/kWh. As DEP focuses on deploying cost-effective winter-time DSM, it is reasonable to expect that the system will return to summer peaking. At that time, a summer-only value for avoided T&D should be used.

Q. How did you arrive at your recommended avoided T&D component value?

A. I arrived at the $0.005778/kWh value for avoided T&D capacity by using the Current Values approach using publicly available FERC Form 1 data (Exhibit DG-4). The Current Values approach calculates the current value of the transmission system per kW of transmission peak use. This value represents the cost of serving an additional kW, or conversely the savings from avoiding additional transmission need.

When using this method to calculate avoided transmission capacity associated with solar PV, it is important to weigh the avoided transmission capacity value by solar PV's system capacity credit. To represent the avoided transmission capacity value on a $/kWh basis, the avoided cost must be divided by the expected energy

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[7] At the time of this filing, the Company has provided distribution data for just the past three years and with transmission data for a longer period (since 2000), but for only some transmission projects (new line and reconductor projects).

production of the incremental solar PV. These steps have been incorporated into my calculation.

Environmental Costs

Q. How has DEP presented the 2018 value associated with avoided Environmental Costs?

A. DEP represented the value as $0.0000 (Witness Brown, Page 8, Table 4).

Q. Please comment on DEP's use of a zero value for the Environmental Costs Component.

A. As with the avoided T&D Capacity component, a value of zero was used under the 2014 Settlement Agreement as a placeholder initially because quantification required study. It is possible to quantify avoided environmental costs, specifically related to coal ash disposal, and therefore this component should now be quantified. It is not clear from DEP testimony that the Company has attempted to calculate or quantify this component at this time. It is unreasonable to assume that the current value is zero.

Q. Why is a zero value inappropriate for the Environmental Cost component?

A. There are many environmental costs that can be avoided through the decreased use of conventional combustion technologies such as coal, oil, and natural gas. Some, like criteria pollutant costs, have been reported as a separate component by DEP. Other costs, such as the capital costs related to management and disposal of waste and wastewater produced by coal-generators, are substantial but their avoidance have not yet been included.

Q. What other costs do you believe should be included in DEP's calculation of avoided Environmental Costs at this time?

A. I believe that the cost of coal ash disposal should be included as an avoided environmental cost. DEP's coal-fired power plants, as well as the coal-fired power plants owned by Duke Energy Carolinas, LLC that are dispatched for the benefit of DEP customers,[8] generate large quantities of coal ash waste. This is regulated under the U.S. EPA's recently revised Coal Combustion Residuals (CCR) rule, as well as by the North Carolina Coal Ash Bill.[9] There are three broad categories of costs associated with coal ash waste:

1) Variable operational costs associated with coal ash disposal for each kWh of coal-fired generation.

2) Capital costs associated with building new impoundments. As coal ash impoundments fill up, new ones may be constructed.

3) Costs associated with the risk that an impoundment will leak and that leak will require clean up.[10]

Therefore, to the extent that NEM distributed energy resources reduce the dispatch of coal units, those NEM resources are allowing the Company to avoid the environmental costs associate with coal ash waste.

Q. How would you value the avoided Environmental Costs associated with coal ash waste?

A. NEM distributed energy resources allow for the utility to burn less coal, and therefore for the coal ash impoundments to fill less quickly. This has an economic value that is attributable to NEM resources and should be quantified and included in the DEP's calculations. We requested data in discovery to quantify the $/kWh cost based on the capacity of existing coal ash impoundments, the cost to build a new impoundment, and the quantity of coal ash generated at each coal-fired electric generating plant. However, we have not been provided with this data by DEP, and therefore I was unable to perform this calculation. The Company's

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[8] SC PSC Docket Nos. 2011-158-E and 2011-68-E Settlement Agreement. Available at http://www.regulatorystaff.sc.gov/Documents/News%20Archives/DukeProgressSettlement.pdf.

[9] 2014 N.C. Sess, Laws 122; 2014 N.C. Ch. 122; 2013 N.C. SB 729.

[10] These risks and costs were laid out in the "Regulatory Impact Analysis: EPA's 2018 RCRA Proposed Rule Disposal of Coal Combustion Residuals from Electric Utilities; Amendments to the National Minimum Criteria (Phase One). March, 2018."

failure to disclose this information prevents me from doing the calculation, but the Company would still be able to perform this calculation and provide the $/kWh value to the Commission.

Line Losses

Q. How has DEP presented the value associated with the 2018 line loss calculations?

A. DEP presented the avoided line loss value as $0.000686/kWh for Small PV, and $0.000684/kWh for Large PV (Table 5, page 8 of Witness Brown's Testimony).

Q. Do you have any recommendations regarding DEP's line loss calculations?

A. Yes. In response to CCL and SACE discovery request 1-3, DEP provided a line loss study that relied on data from 2010. This study was done before the Duke Energy-Progress Energy merger, and therefore before the two companies began jointly dispatching to meet combined load.

DEP should conduct a new or updated line loss study for marginal line losses on the joint DEP-DEC Carolinas system in order to quantify avoided energy, generating capacity, and transmission capacity costs associated with line losses. The study should be specific to the Company's expected future hourly load forecasts and expected generator and transmission infrastructure. The study should use a solar PV profile rather than a fixed constant output profile, since most NEM resources in the near future are expected to be PV resources in DEP territory. Marginal line losses should be used because line losses increase with the square of the current, and marginal losses capture the actual impact of adding another kW of solar to the distribution system.

5. CONCLUSION

Q. Please summarize your recommendations regarding the net energy metering methodology—2018 application.

A. My recommendations are:

4. The Commission should require DEP to immediately adopt an avoided T&D value of $0.005778/kWh based on the Current Values approach described above.

5. DEP should conduct a study to more specifically quantify the avoided environmental cost of coal ash disposal as it relates to distributed PV to inform future NEM valuation updates in the fuel cost proceedings.

6. DEP should perform an updated line losses study to quantify marginal line losses associated with avoided energy, generating capacity and transmission capacity costs across DEP's current footprint. This study should be based on the Company's forecasted load and generation, and it should use a solar PV profile (not a fixed constant output profile).

Q. Does this conclude your testimony?

A. Yes.

Devi Glick, Associate

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Associate*, January 2018 – Present

Conducts research and provides consulting on energy sector issues. Examples include:

- modeling for resource planning using PLEXOS utility planning software, analysis of system-level cost impacts of energy efficiency nationwide;
- rate design for distributed energy resources within the state of Hawaii; and
- developing a manual and providing quality control for a tool to analyze the impacts of climate measures and energy policies in Morocco.

Rocky Mountain Institute, Basalt, CO. August 2012 – September 2017

Senior Associate

- Led technical analysis, modeling, training and capacity building work for utilities and governments in Sub-Saharan Africa around integrated resource planning for the central electricity grid energy and identified over a billion dollars in savings based on improved resource-planning processes.
- Represented RMI as a content expert and presented materials on electricity pricing and rate design at conferences and events.
- Led a project to research and evaluate utility resource planning and spending processes, focusing specifically on integrated resource planning, to highlight systematic overspending on conventional resources and underinvestment and underutilization of distributed energy resources as a least-cost alternative.

Associate

- Led modeling analysis in collaboration with NextGen Climate America which identified a CO_2 loophole in the Clean Power Plan of 250 million tons, or 41 percent of EPA projected abatement, and was submitted as an official federal comment, and led to a modification to address the loophole in the final rule.
- Led financial and economic modeling in collaboration with a major U.S. utility to quantify the impact that solar PV would have on their sales, and helped them identify alternative business models that would allow them to recapture a significant portion of this at-risk value.

- Supported the planning, content development, facilitation, and execution of numerous events and workshops with participants from across the electricity sector for RMI's Electricity Innovation Lab (eLab) initiative.
- Co-authored two studies reviewing valuation methodologies for solar PV and laying out new principles and recommendations around pricing and rate design for a distributed energy future in the United States. These studies have been highly cited by the industry and submitted as evidence in numerous Public Utility Commission rate cases.

The University of Michigan, Ann Arbor, MI. *Graduate Student Instructor*, September 2011 – July 2012

Prepared lesson plans, taught classes, graded papers and other coursework, met regularly with students.

The Virginia Sea Grant at the Virginia Institute of Marine Science, Gloucester Point, VA. *Policy Intern*, Summer 2011

Managed a communication network analysis study of coastal resource management stakeholders on the Eastern Shore of the Delmarva Peninsula.

The Commission for Environmental Cooperation (NAFTA), Montreal, QC. *Short Term Educational Program/Intern*, Summer 2010

Researched energy and climate issues relevant to the NAFTA parties to assist the executive director in conducting a GAP analysis of emission monitoring, reporting, and verification systems in North America.

Congressman Tom Allen, Portland, ME. *Technology Systems and Outreach Coordinator*, August 2007 – December 2008

Directed Congressman Allen's technology operation, responded to constituent requests, and represented the Congressman at events throughout southern Maine.

EDUCATION

The University of Michigan, Ann Arbor, MI
Master of Public Policy, Gerald R. Ford School of Public Policy, 2012
Master of Science, School of Natural Resources and the Environment, 2012
Masters Project: *Climate Change Adaptation Planning in U.S. Cities*

Middlebury College, Middlebury, VT
Bachelor of Arts, 2007
Environmental Studies, Policy Focus; Minor in Spanish
Thesis: *Environmental Security in a Changing National Security Environment: Reconciling Divergent Policy Interests, Cold War to Present*

PUBLICATIONS

Fagan, B., R. Wilson, S. Fields, D. Glick, D. White. 2018. *Nova Scotia Power Inc. Thermal Generation Utilization and Optimization: Economic Analysis of Retention of Fossil-Fueled Thermal Fleet To and Beyond 2030 – M08059*. Prepared for Board Counsel to the Nova Scotia Utility Review Board.

Ackerman, F., D. Glick, T. Vitolo. 2018. *Report on CCR proposed rule*. Prepared for Earthjustice.

Lashof, D. A., D. Weiskopf, D. Glick. 2014. *Potential Emission Leakage Under the Clean Power Plan and a Proposed Solution: A Comment to the US EP*A. NextGen Climate America.

Smith, O., M. Lehrman, D. Glick. 2014. *Rate Design for the Distribution Edge*. Rocky Mountain Institute.

Hansen, L., V. Lacy, D.Glick. 2013. *A Review of Solar PV Benefit & Cost Studies*. Rocky Mountain Institute.

TESTIMONY

Public Service Commission of South Carolina (Docket No. 2018-2-E): Direct testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 12, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Surrebuttal testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 4, 2018.

Resume updated May 2018

Exhibit DG-2

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

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.

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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

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)

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

FRAMING THE NEED

- 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.

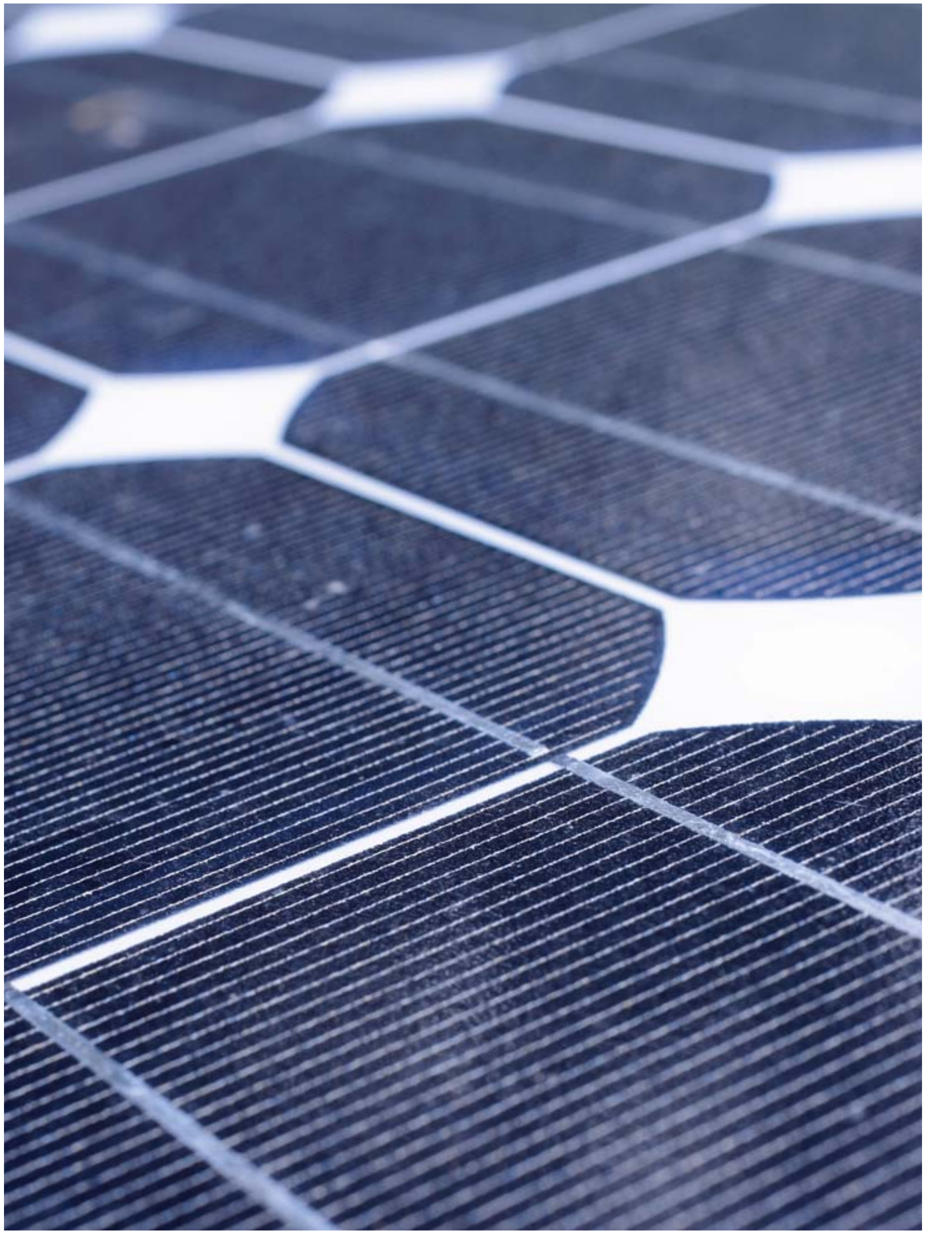


Photo courtesy of Shutterstock

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

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:

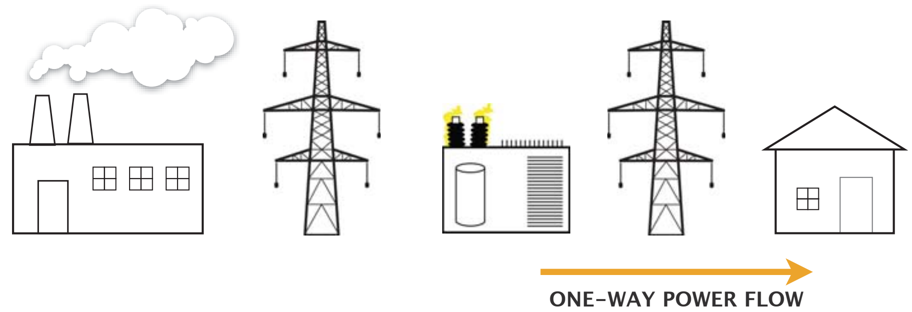
- Demand response
- Electric vehicles
- Thermal storage
- Battery storage

Distributed intelligence

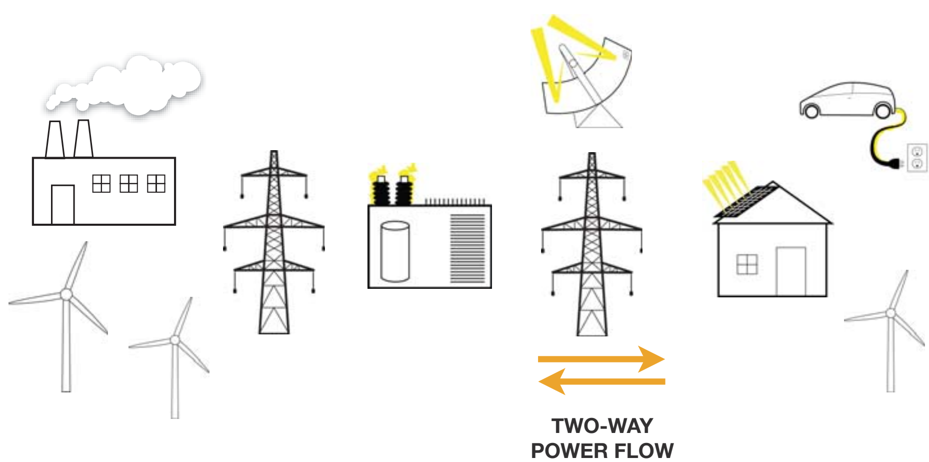
Technologies that combine sensory, communication, and control functions to support the electricity system, and magnify the value of DER system integration. Examples include:

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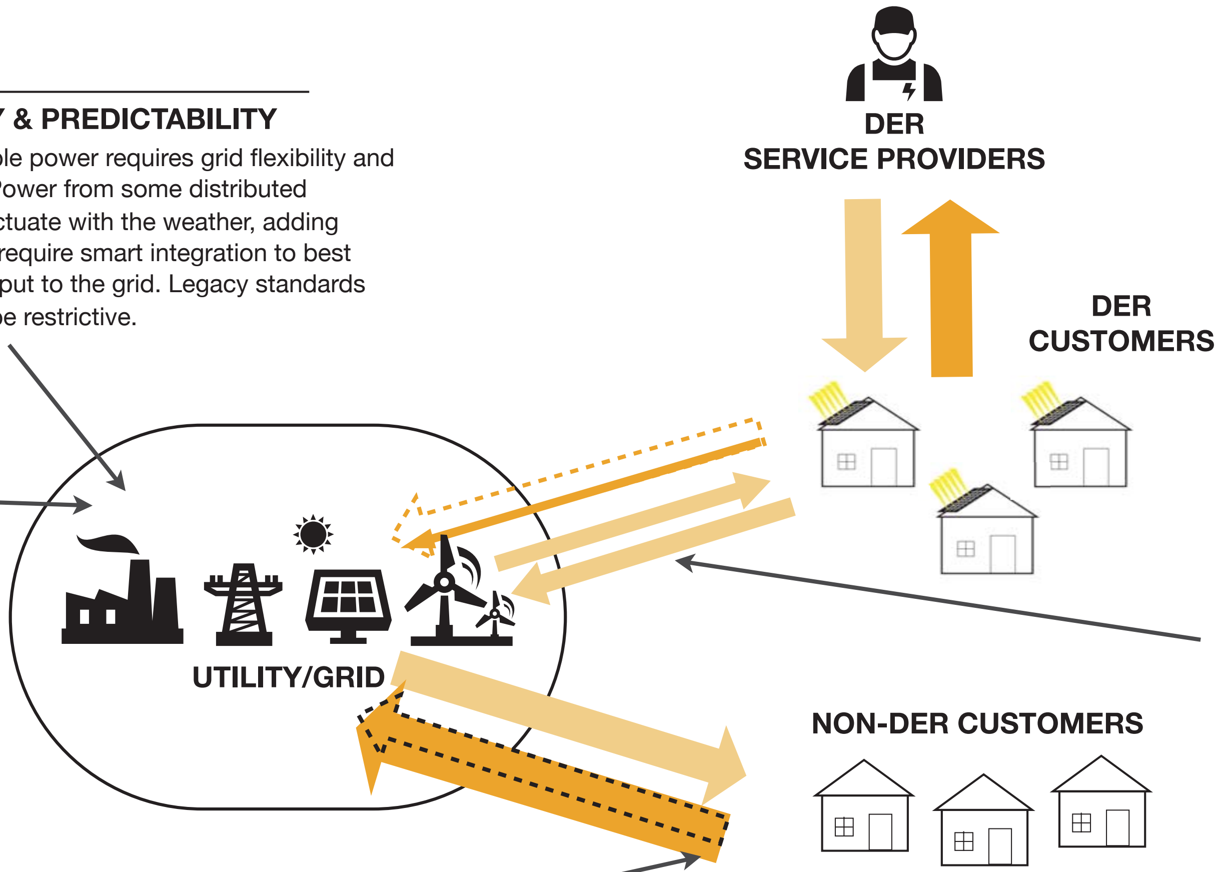
TODAY, OPERATIONAL AND PRICING MECHANISMS DESIGNED FOR AN HISTORICALLY CENTRALIZED ELECTRICITY SYSTEM ARE NOT WELL-ADAPTED TO THE INTEGRATION OF DERS, CAUSING FRICTION AND INEFFICIENCY

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.

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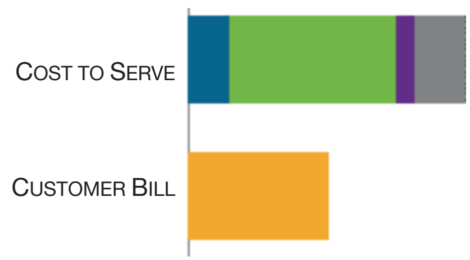
THESE STRUCTURAL MISALIGNMENTS ARE LEADING TO IMPORTANT QUESTIONS, DEBATE, AND CONFLICT

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?

Customer Payment
Generation Cost
Distribution Cost
Transmission Cost
Other Costs

...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

defining value
categories of value
stakeholder implications

02

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.

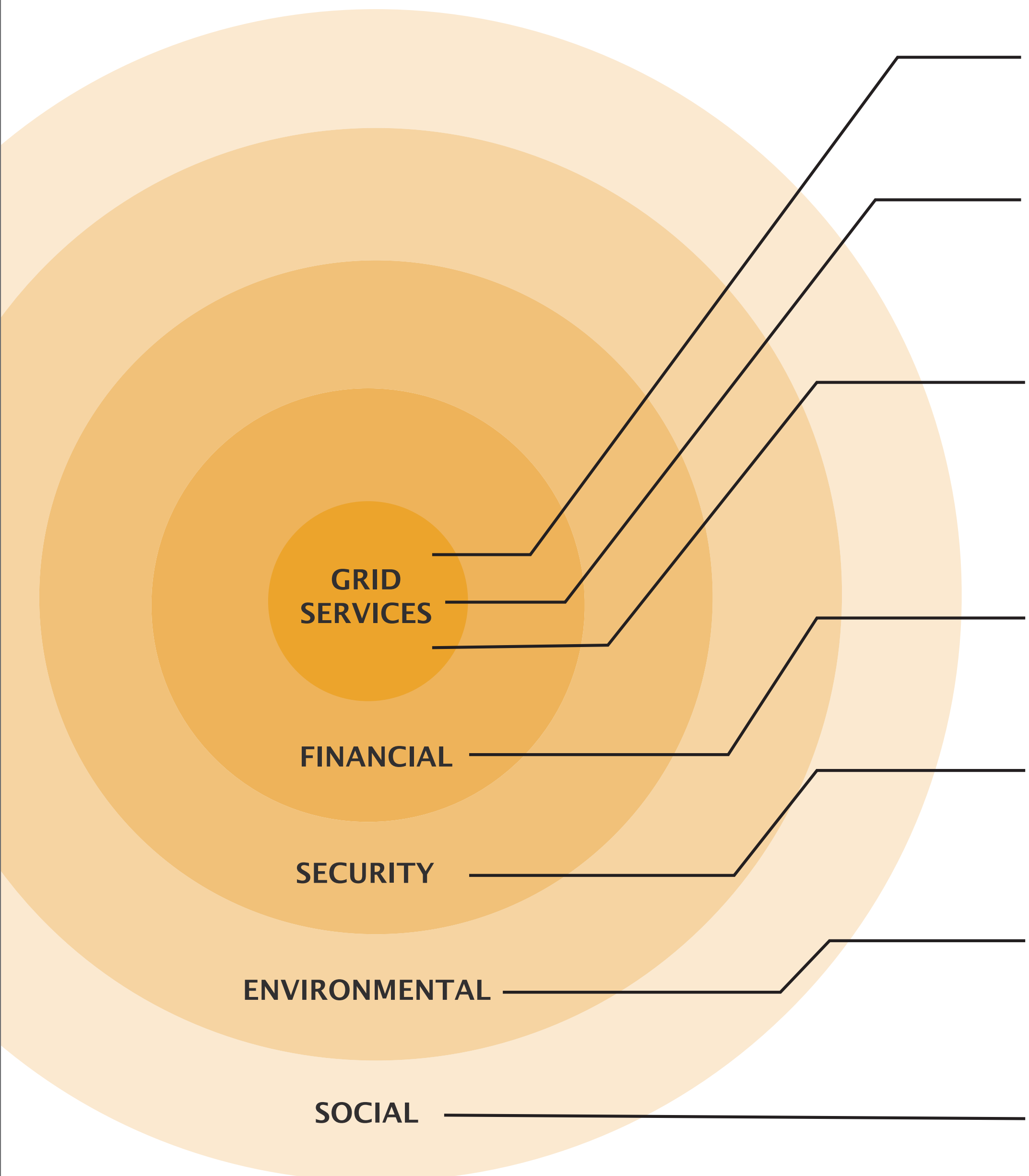
- A variety of categories of benefits or costs of DPV have been considered or acknowledged in evaluating the value of DPV. Broadly, these categories are: energy, system losses, capacity (generation, transmission and distribution), grid support services, financial risk, security risk, environmental and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

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

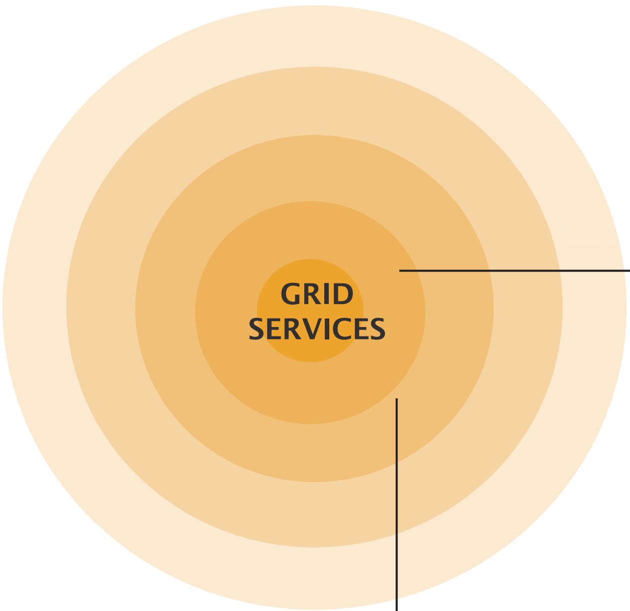
FINANCIAL RISK
- fuel price hedge
- market price response

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



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.

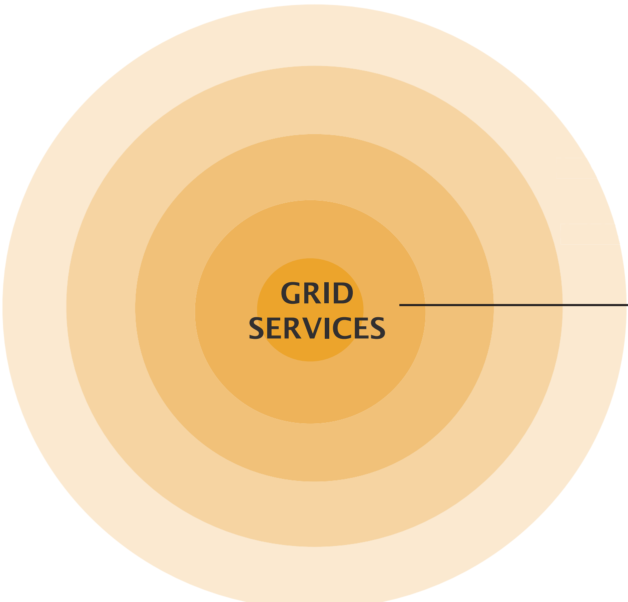
CAPACITY

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

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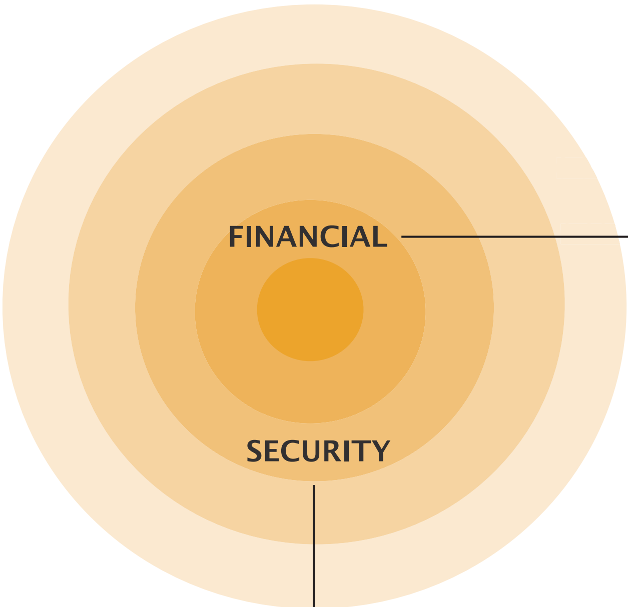


FINANCIAL RISK

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:

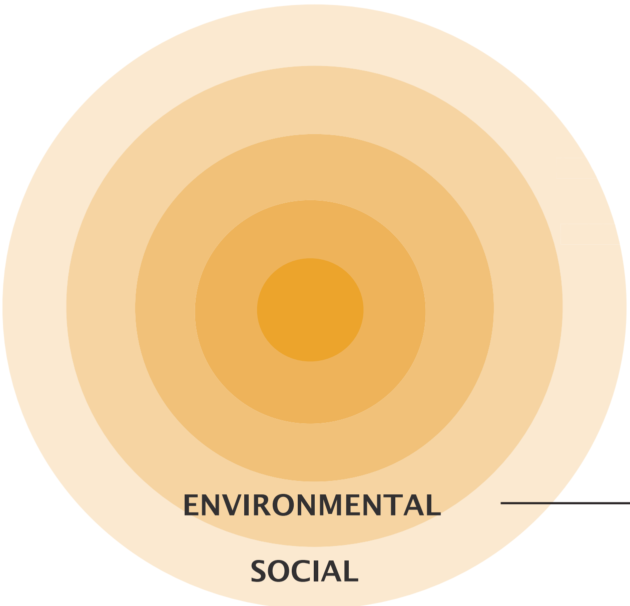
- **Fuel Price Hedge** - The cost that a utility would otherwise incur to guarantee that a portion of electricity supply costs are fixed.

- **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.

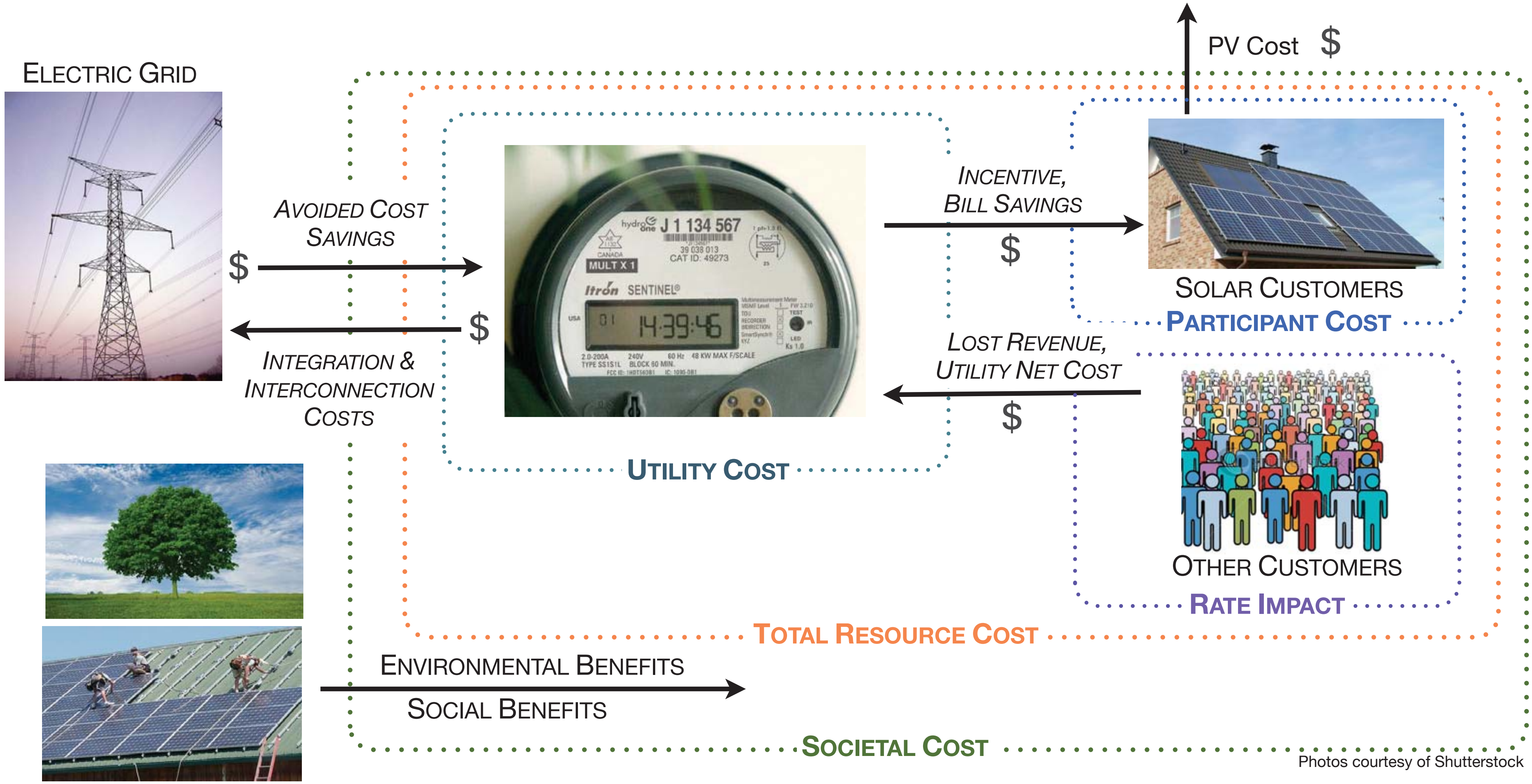
SOCIAL

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.



Photos courtesy of Shutterstock

STAKEHOLDER PERSPECTIVES

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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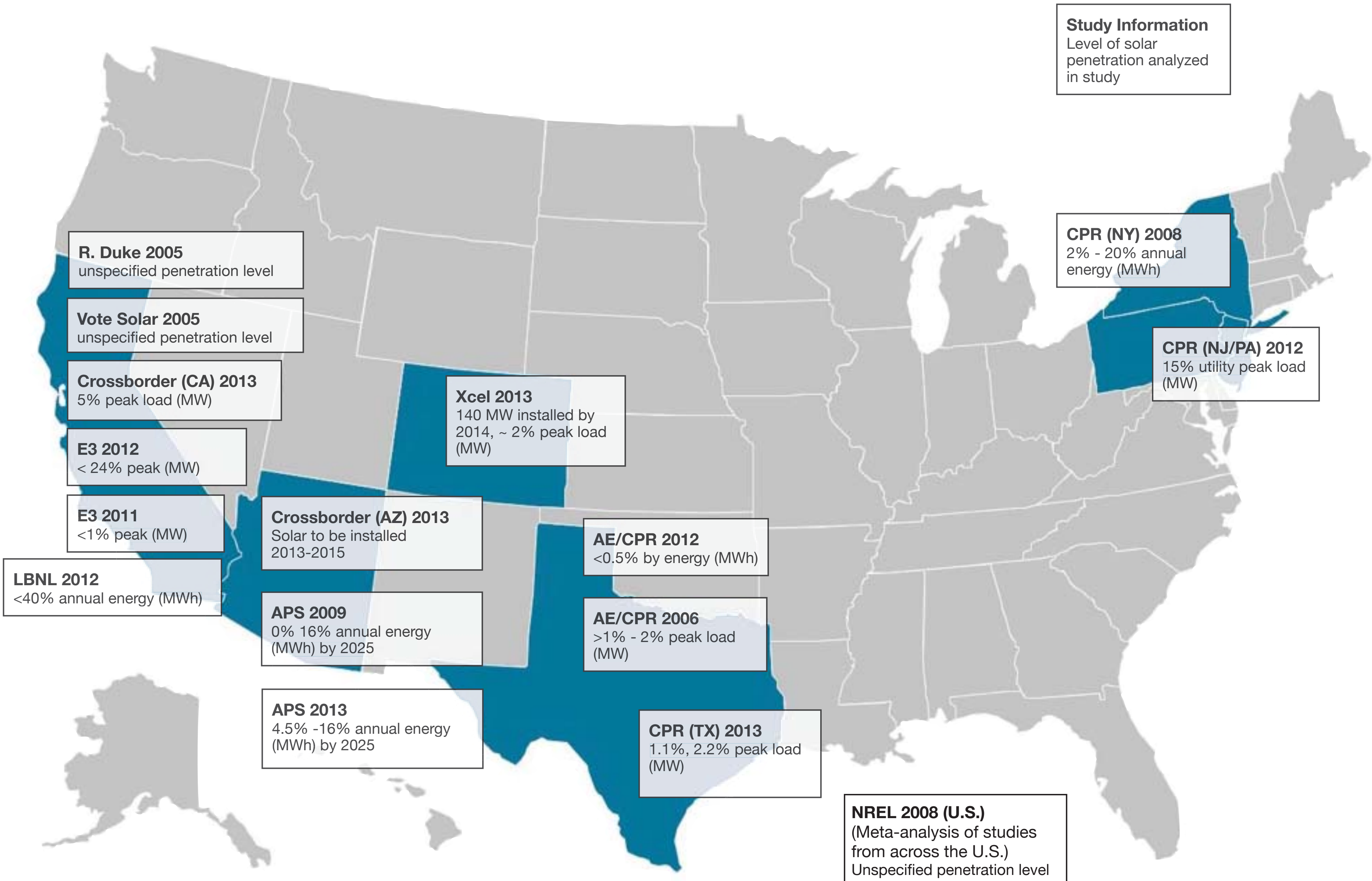
ANALYSIS FINDINGS

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



SUMMARY OF DPV BENEFITS AND COSTS

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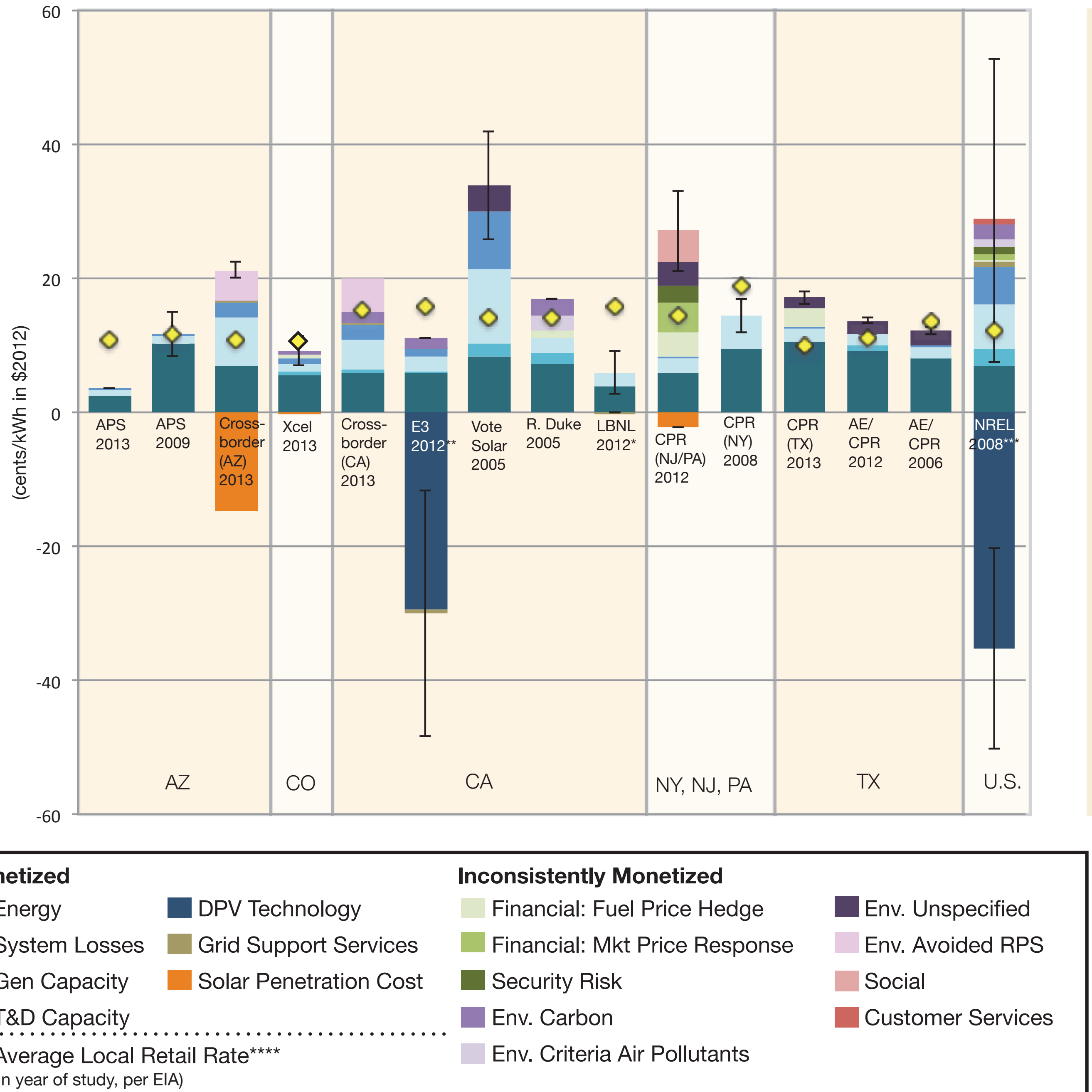
BENEFITS AND COSTS OF DISTRIBUTED PV BY STUDY



INSIGHTS

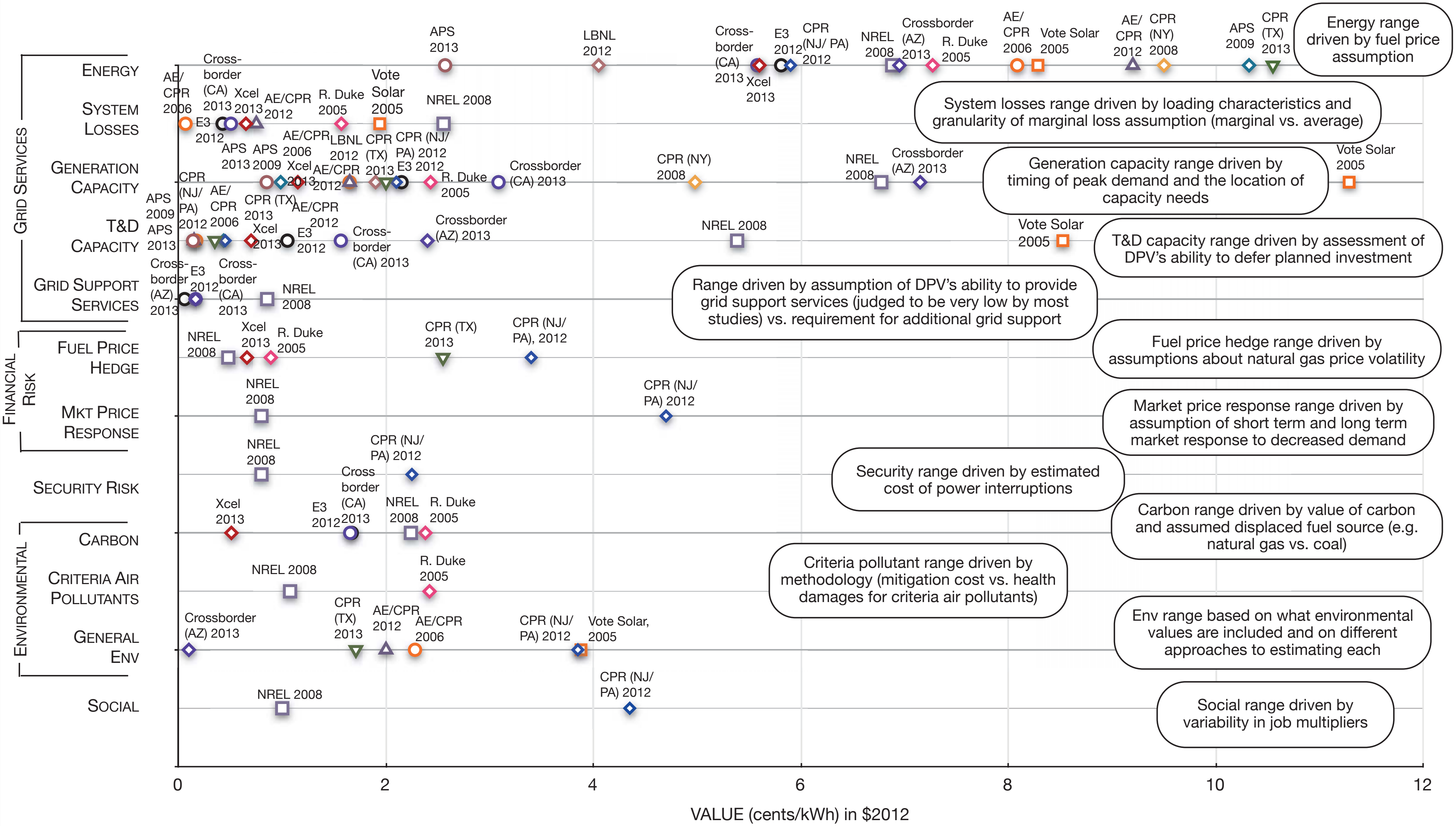
- No study comprehensively evaluated the benefits and costs of DPV, although many acknowledge additional sources of benefit or cost and many agree on the broad categories of benefit and cost.
- There is a significant range of estimated value across studies, driven primarily by differences in local context, 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 general agreement on overall approach to estimating energy 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.

* 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.

BENEFIT ESTIMATES

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

PUBLISHED AVERAGE BENEFIT ESTIMATES*

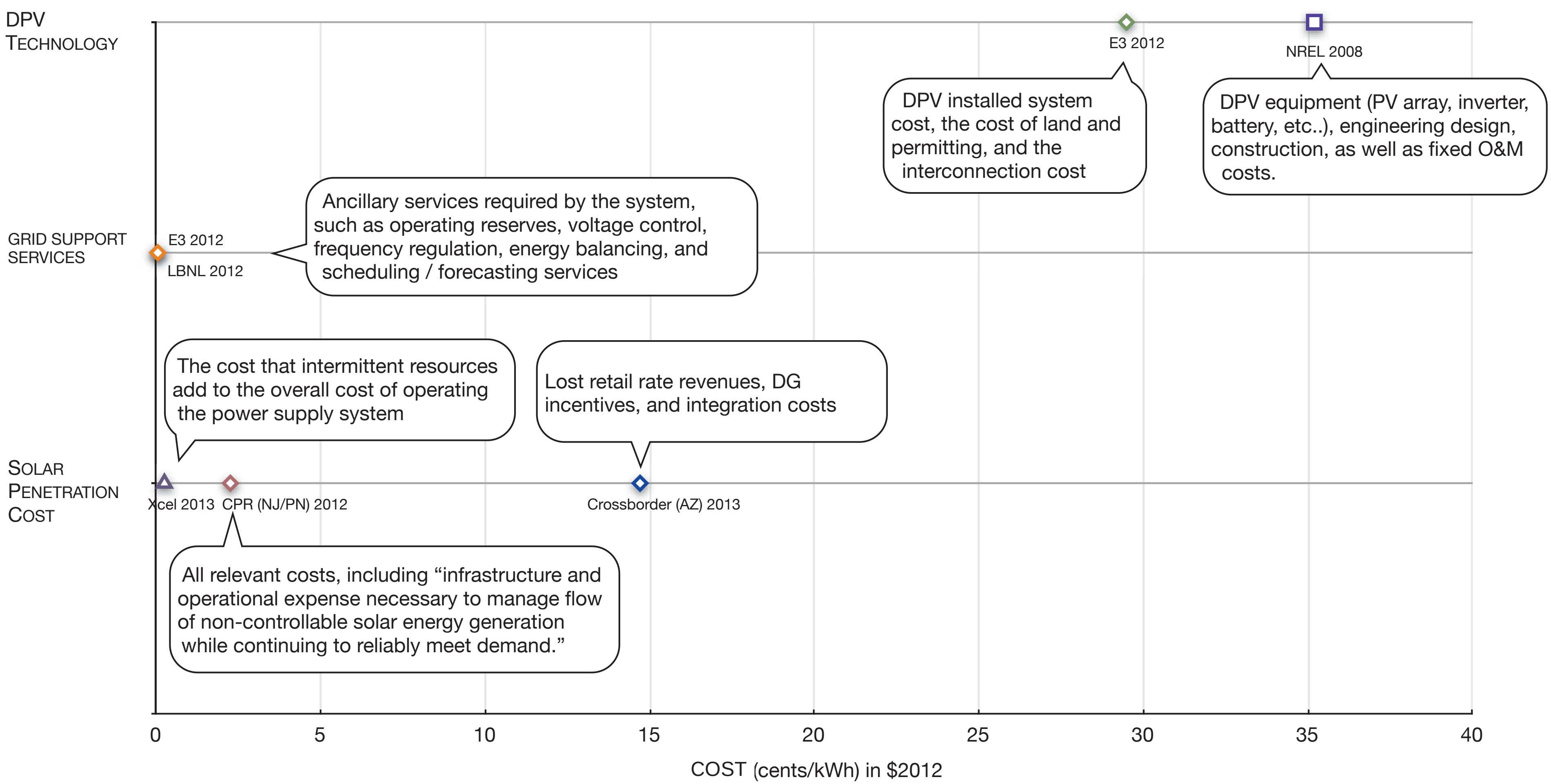


*For the full range of values observed see the individual methodology slides.

COST ESTIMATES

COSTS ASSOCIATED WITH INCREASED DPV DEPLOYMENT ARE NOT ADEQUATELY ASSESSED

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

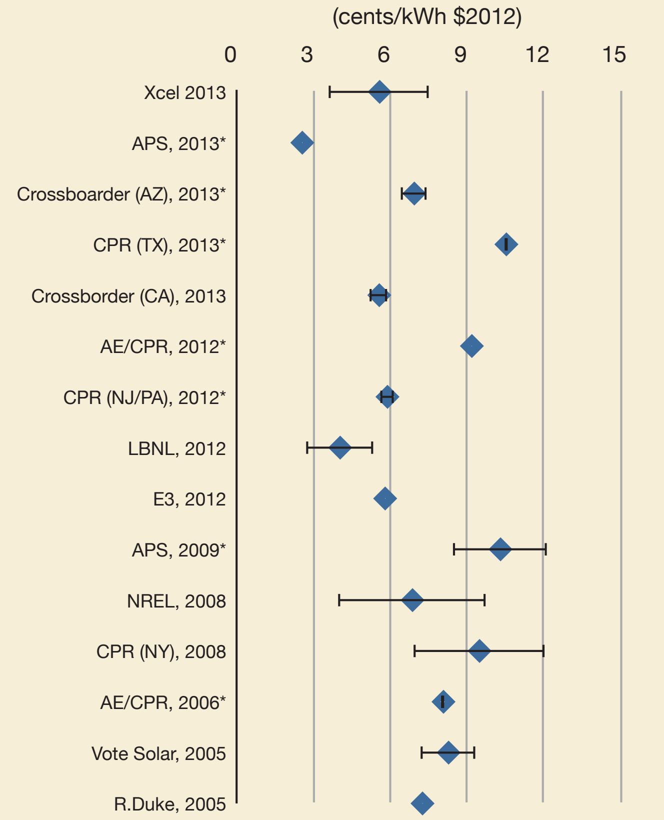
There is broad agreement on the general approach to calculating energy value, although numerous differences in methodological details. Energy is frequently the most significant source of benefit.

- 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.

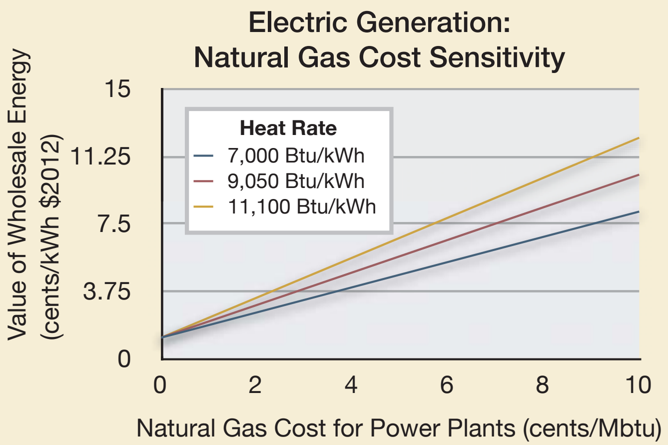
ENERGY BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES



* = value energy savings that result from avoided energy losses

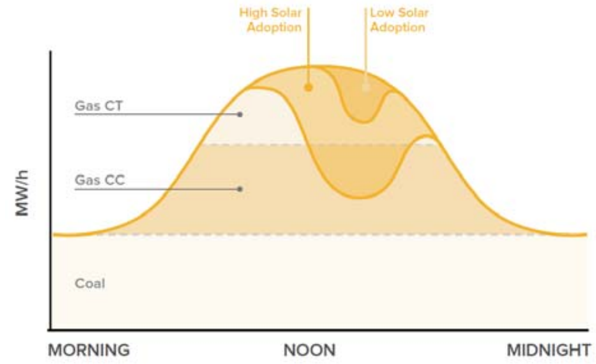
Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.

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

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

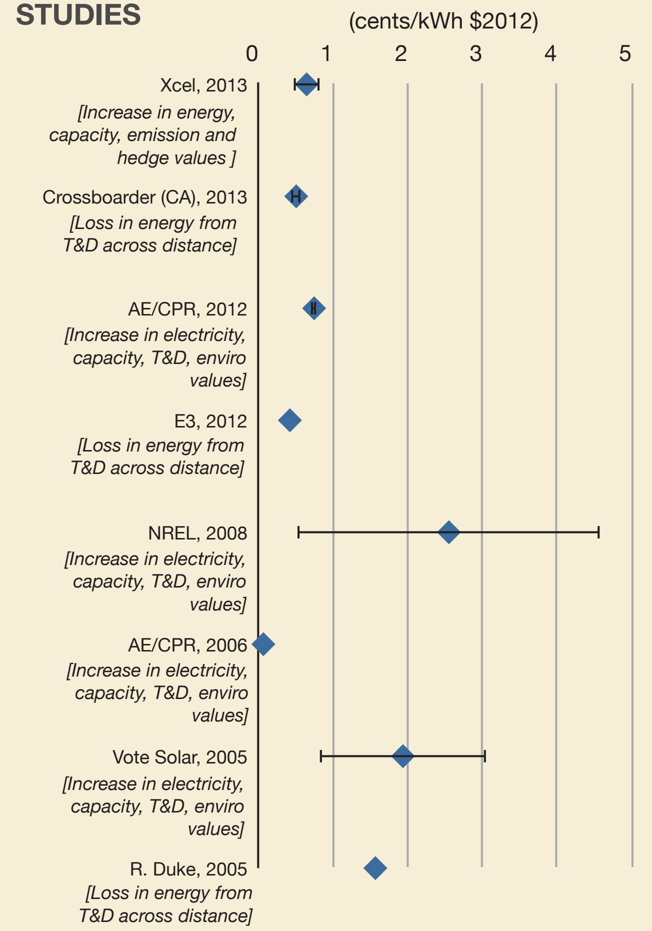
Losses are generally recognized as a value, although there is significant variation around what type of losses are included and how they are assessed. Losses usually represent a small but not insignificant source of value, although some studies report comparatively high values.

- 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 characterization**—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

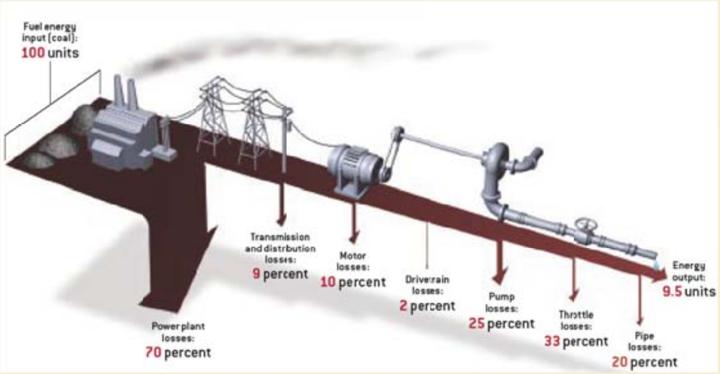


Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.

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

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.

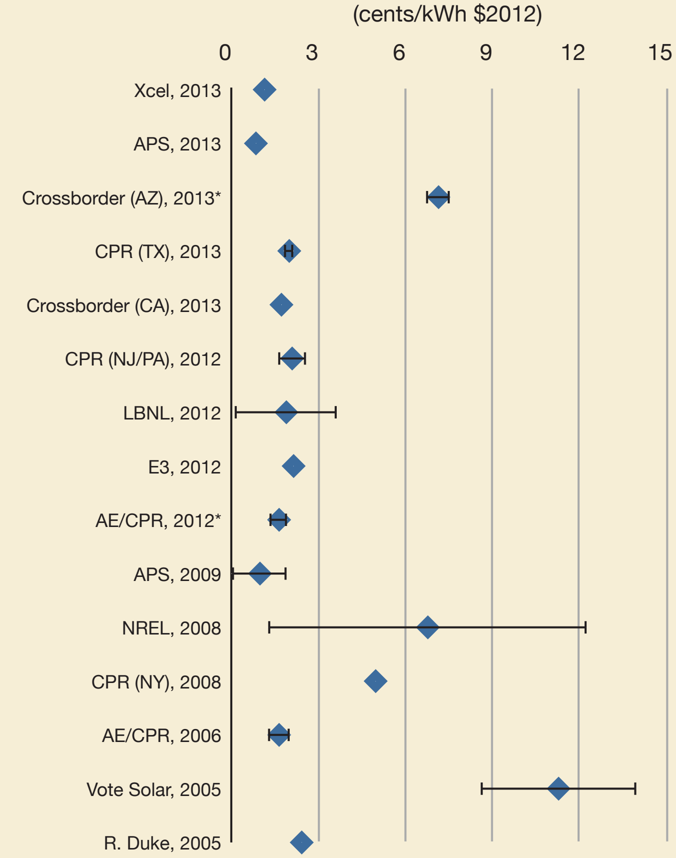
APPROACH OVERVIEW

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

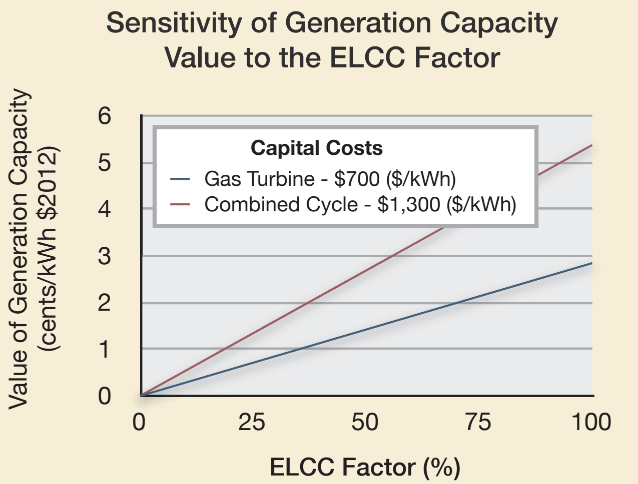


* = value includes generation capacity savings that result from avoided energy losses

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

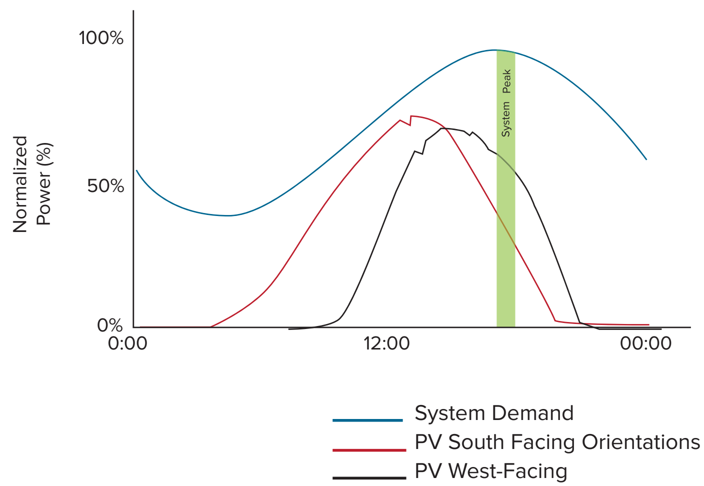
GENERATION CAPACITY (CONT'D)

SENSITIVITIES TO KEY INPUT ASSUMPTIONS



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

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.

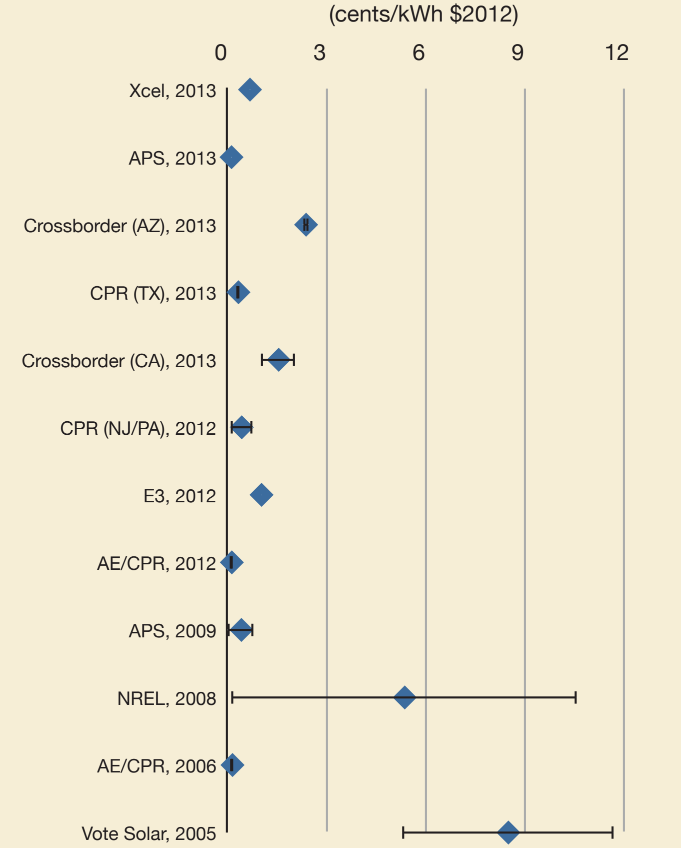
APPROACH OVERVIEW

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)

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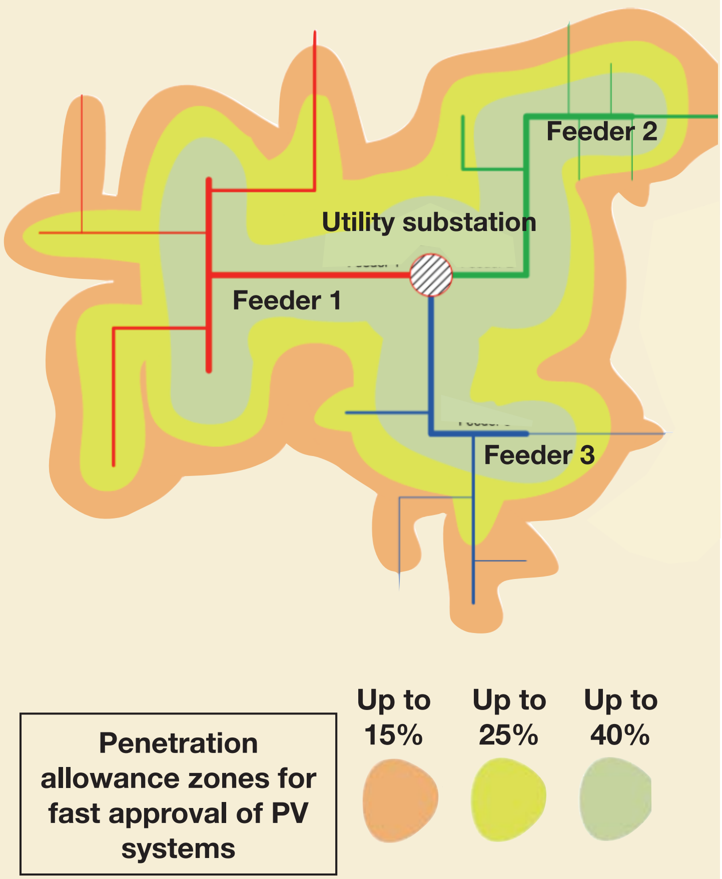
LOCATIONAL CONSIDERATIONS AT THE DISTRIBUTION LEVEL



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

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.

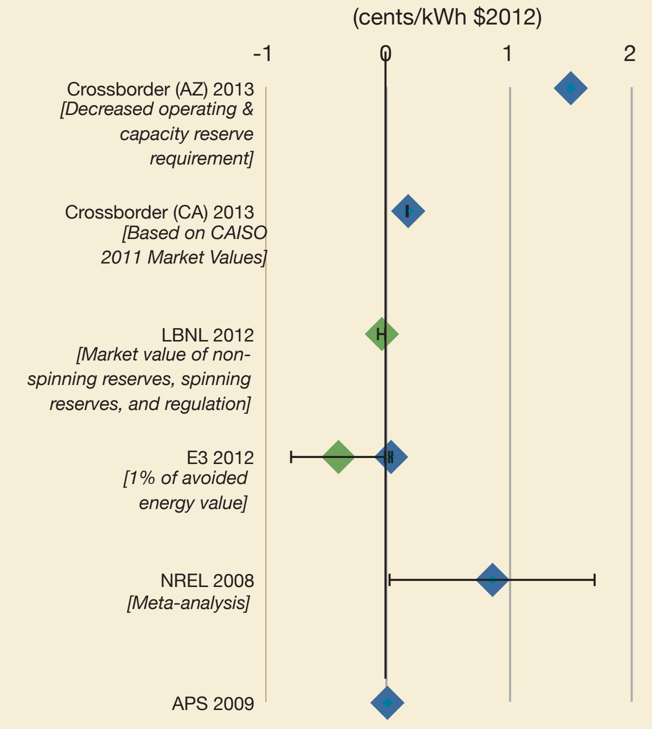
APPROACH OVERVIEW

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

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).

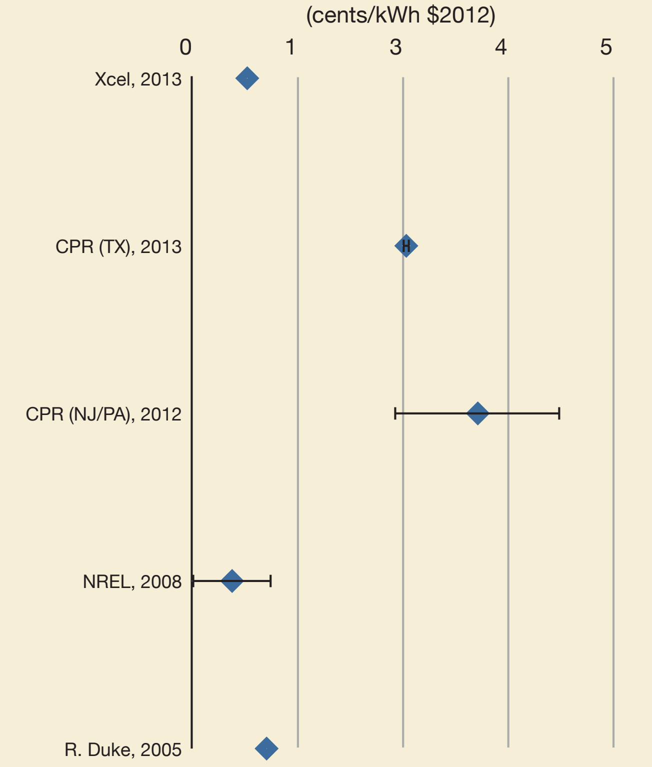
WHY AND HOW VALUES DIFFER

- **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

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)."

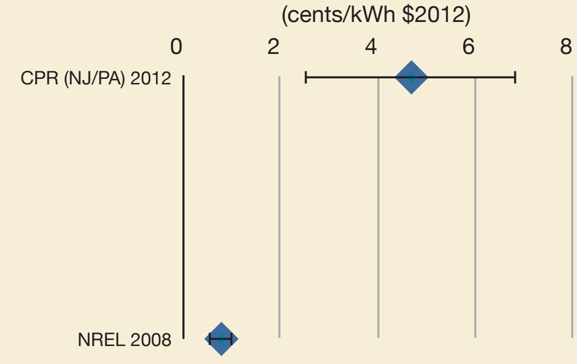
INSIGHTS & IMPLICATIONS

- 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

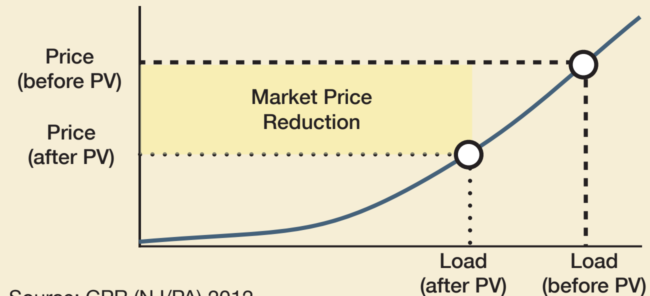
Technologies powered by risk-free fuel sources (such as wind) and technologies that increase the efficiency of energy use and decrease consumption would also have similar effects.

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

Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

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

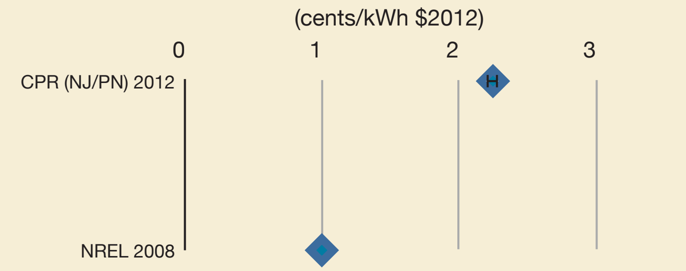
- The value of increased reliability is significant, but there is a need to quantify and demonstrate how much value can be provided by DPV. Rules-of-thumb assumptions and calculations for security impacts require significant analysis and review.

- 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.

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

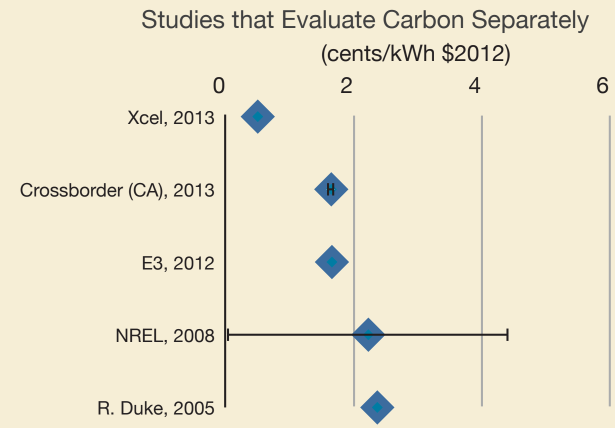
By and large, studies that addressed carbon focused on the compliance costs or fees associated with future carbon emissions, and conclude that carbon reduction can increase DPV's value by more than two cents per kilowatt-hour, depending heavily on the price placed on carbon. While there is some agreement 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.

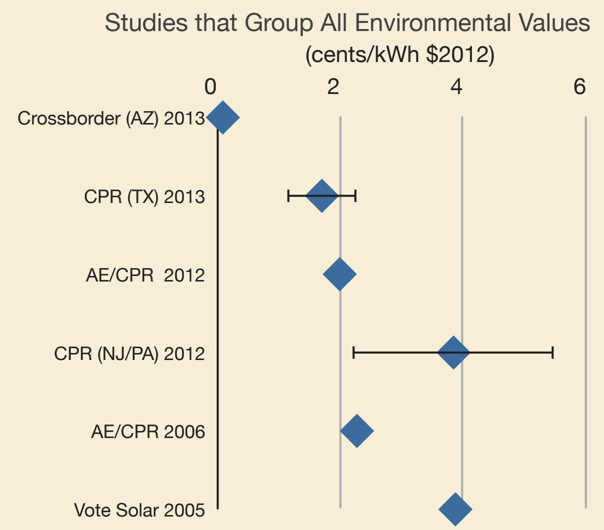
Carbon reduction benefit is the amount of carbon displaced times the price of reducing a ton of carbon. The amount of carbon displaced is directly linked to the amount of energy displaced, when it is displaced, and the carbon intensity of the resource being displaced.

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

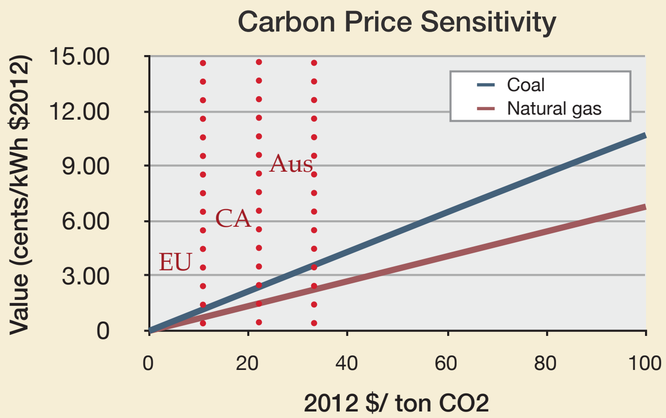


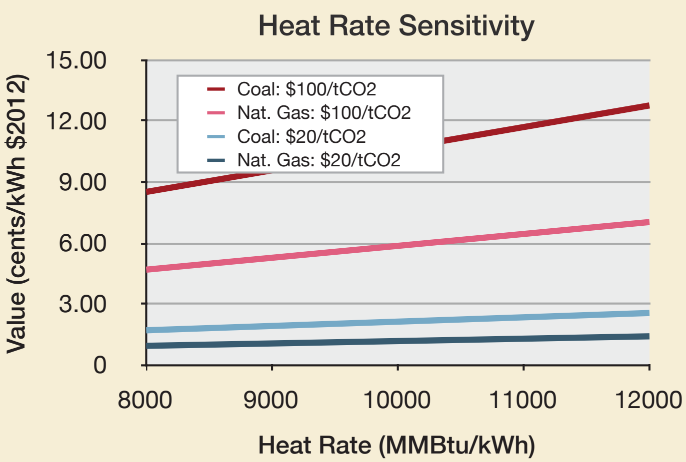


Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.

ENVIRONMENT: CARBON DIOXIDE
(CONT'D)

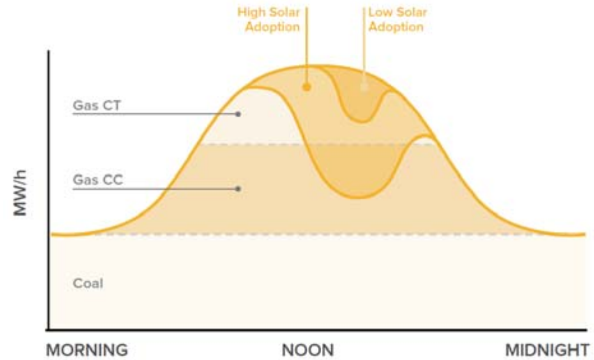
SENSITIVITY TO KEY INPUT ASSUMPTIONS





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

Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

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.

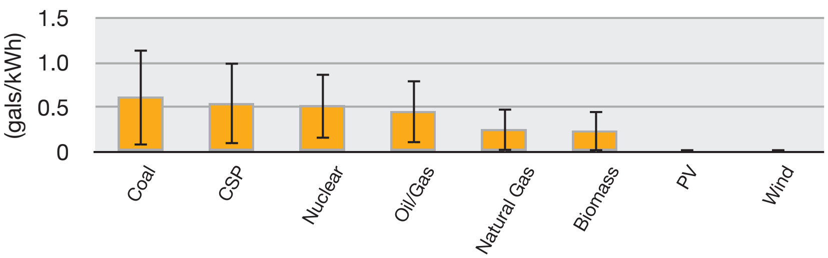
ENVIRONMENT: OTHER FACTORS

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.

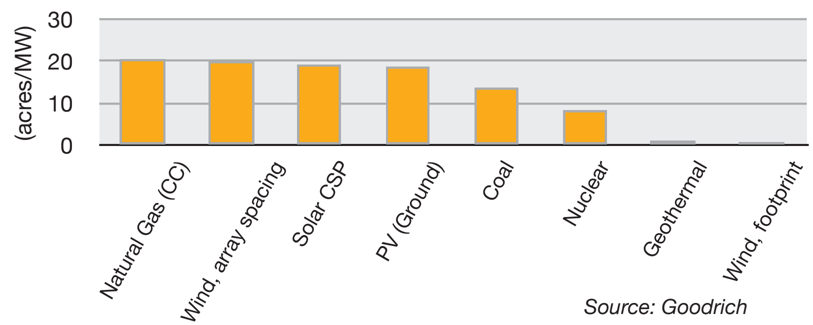
Fthenakis, V., Hyungl, C., *Life-cycle Use of Water in U.S. Electricity Generation.* Renewable and Sustainable Energy Review 14, Sept. 2010. pp.2039-2048.

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

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.

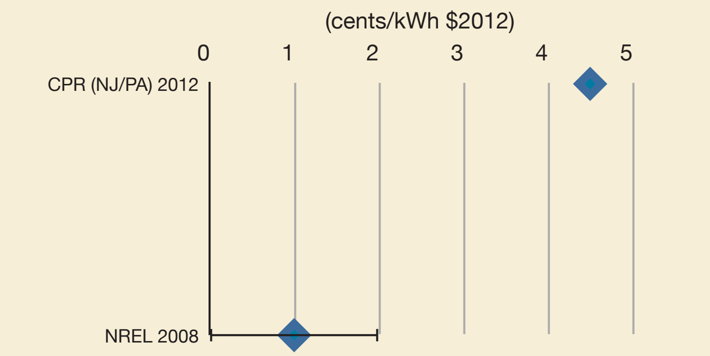
APPROACH OVERVIEW

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.

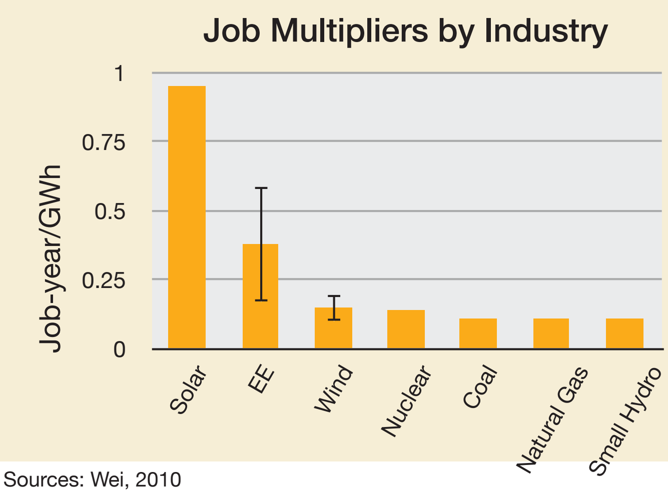
IMPLICATIONS AND INSIGHTS

- 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.



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

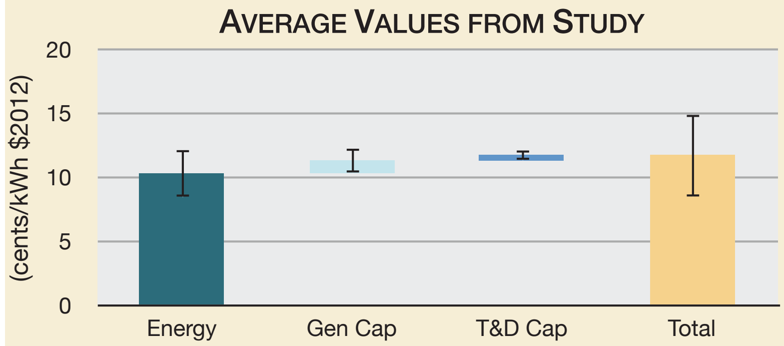
KEY COMPONENTS INCLUDED IN EACH STUDY OVERVIEW

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

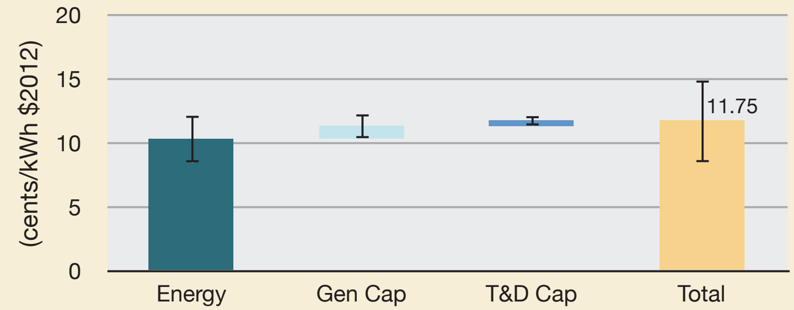
Study Characteristics	
STUDY OBJECTIVE	To determine the potential value of DPV for Arizona Public Service, and to understand the likely operating impacts.
GEOGRAPHIC FOCUS	Arizona Public Service territory
SYSTEM CONTEXT	Vertically integrated IOU, 15% RPS by 2025 with 30% distributed resource carveout
LEVEL OF SOLAR ANALYZED	0-16% 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

Average Values from Study



**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).

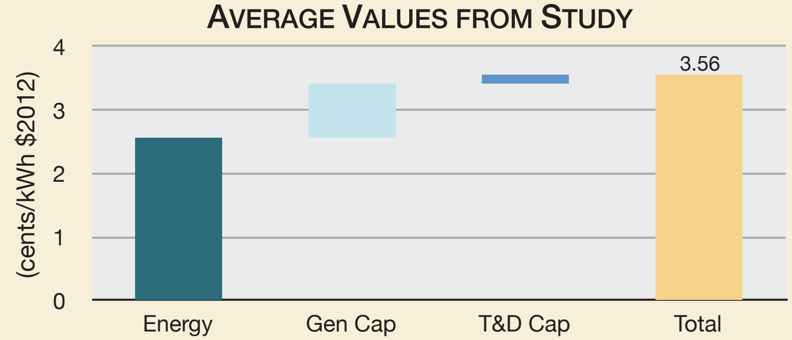
T&D capacity value includes benefits from reduced losses, modeled with a combination of hourly system-wide and feeder-specific modeling. T&D capacity value is determined by comparing DPV's dependable capacity to APS's T&D investment plan. For T&D, as compared to generation, dependable capacity is determined 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.

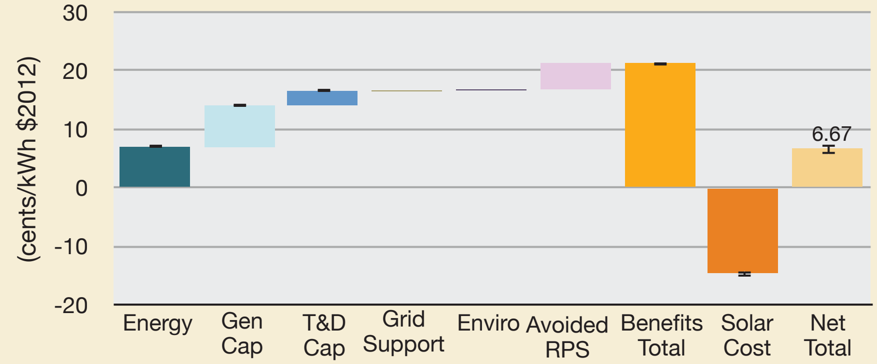
Study Characteristics	
STUDY OBJECTIVE	To determine how demand-side solar will impact APS's ratepayers; a response to the APS 2013 study.
GEOGRAPHIC FOCUS	Arizona Public Service territory
SYSTEM CONTEXT	Vertically integrated IOU, 15% RPS by 2025
LEVEL OF SOLAR ANALYZED	DPV likely to be installed between 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

Average Values from Study



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

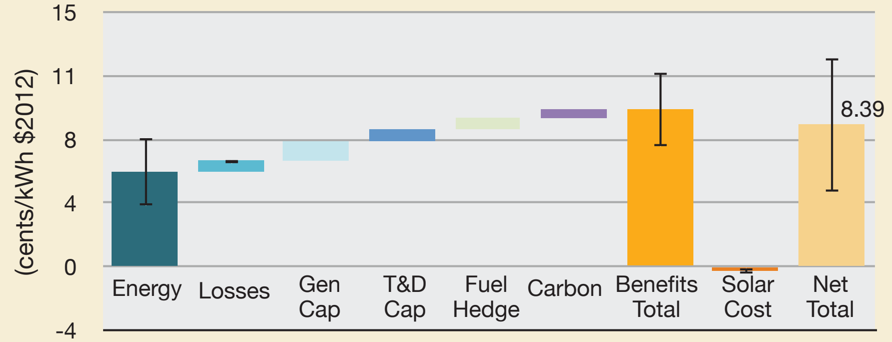
STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To determine the costs and benefits of DPV on the Public Service Company of Colorado's electric power supply system at current penetration levels and projections for near-term penetration levels.
GEOGRAPHIC FOCUS	Public Service Company of Colorado's territory
SYSTEM 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

AVERAGE VALUES FROM STUDY



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.

TECHNICAL POTENTIAL FOR LOCAL DISTRIBUTED PHOTOVOLTAICS IN CALIFORNIA

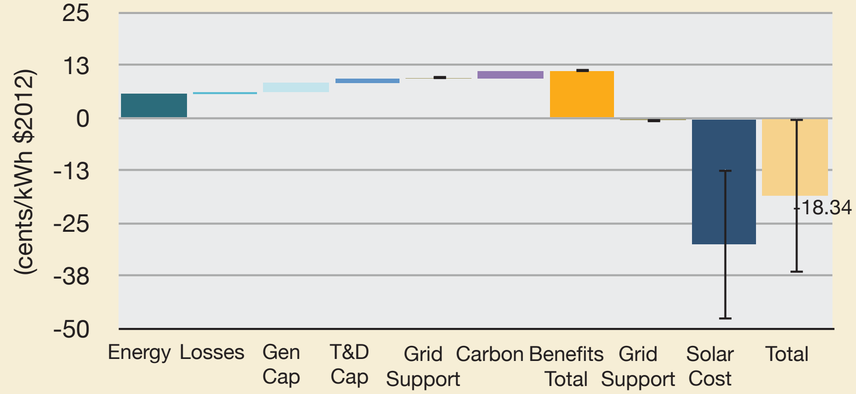
STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To estimate the technical potential of local DPV in California, and the associated costs and benefits.
GEOGRAPHIC FOCUS	California
SYSTEM CONTEXT	California's 3 investor-owned utilities (IOU): PG&E, SDG&E, SCE
LEVEL OF SOLAR ANALYZED	< 24% system peak load
STAKEHOLDER 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

AVERAGE VALUES FROM STUDY



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

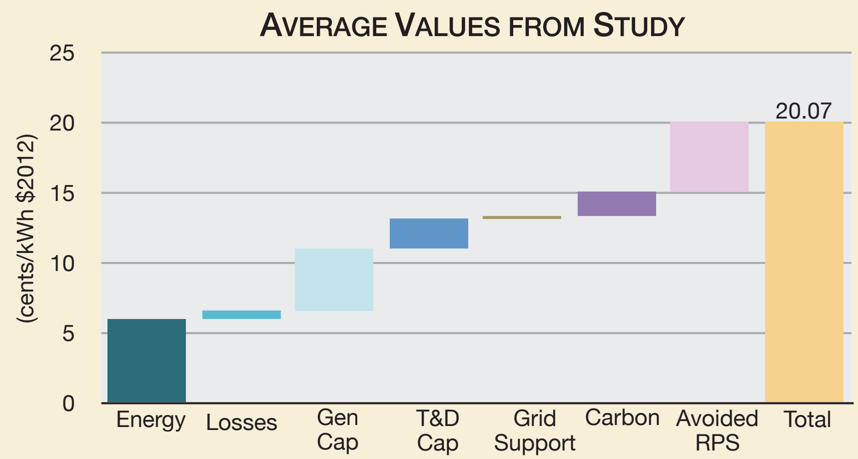
Highlights

- 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.

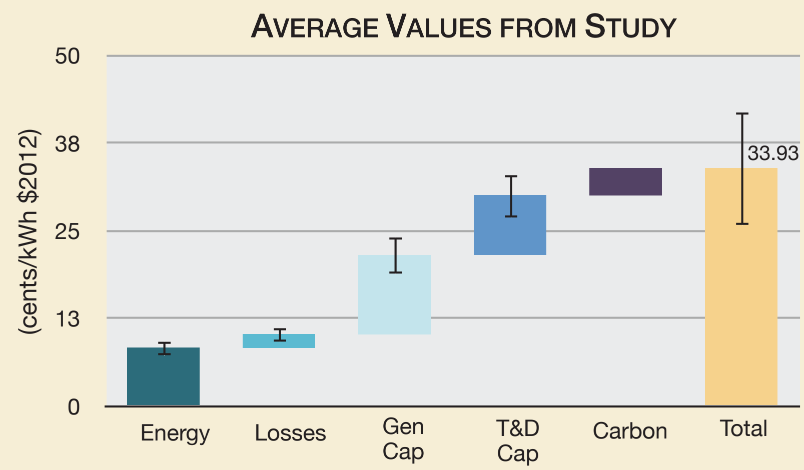
Avoided RPS: The avoided net cost of procuring renewable resources to meet an RPS Portfolio that is a percentage of total retail sales due to a reduction in retail loads.

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

ACCELERATING RESIDENTIAL PV EXPANSION: DEMAND ANALYSIS FOR COMPETITIVE ELECTRICITY MARKETS

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

AVERAGE VALUES FROM STUDY

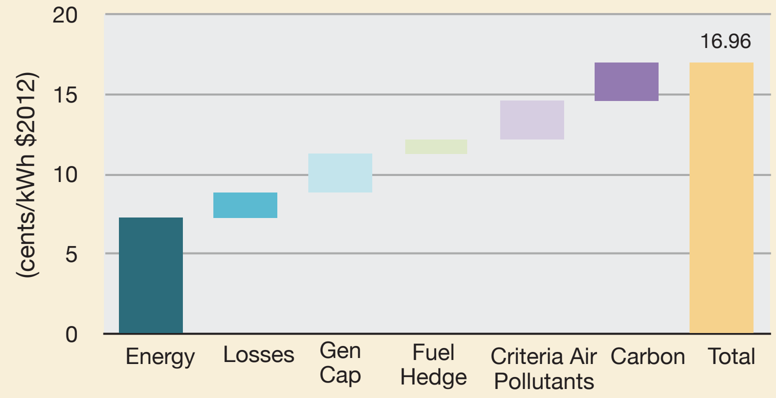


**Chart data only reflects California assessment for comparison*

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.

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

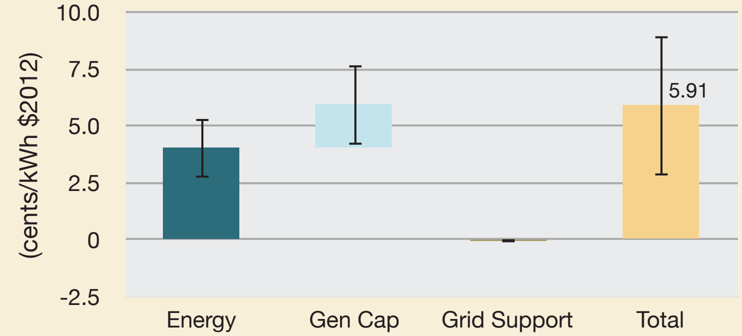
STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To quantify the change in value for a subset of economic benefits (energy, capacity, ancillary services, DA forecasting error) that results from using renewable generation technologies (wind, PV, CSP, & Thermal Energy Storage) at different penetration levels.
GEOGRAPHIC 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

AVERAGE VALUES FROM STUDY



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.

CLEAN POWER RESEARCH, 2012

THE VALUE OF DISTRIBUTED SOLAR ELECTRIC GENERATION TO NEW JERSEY AND PENNSYLVANIA

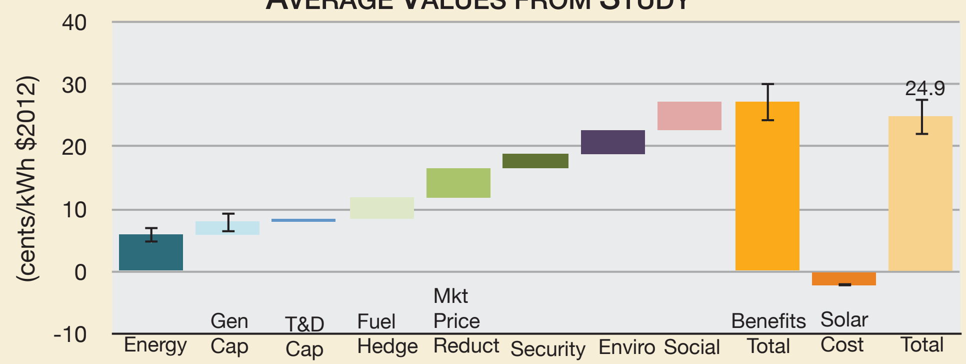
STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To quantify the cost and value components provided to utilities, ratepayers, and taxpayers by grid-connected, DPV in Pennsylvania and New Jersey.
GEOGRAPHIC FOCUS	7 cities across PA and NJ
SYSTEM CONTEXT	PJM ISO
LEVEL OF SOLAR ANALYZED	15% of system peak load, totaling 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

AVERAGE VALUES FROM STUDY



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.

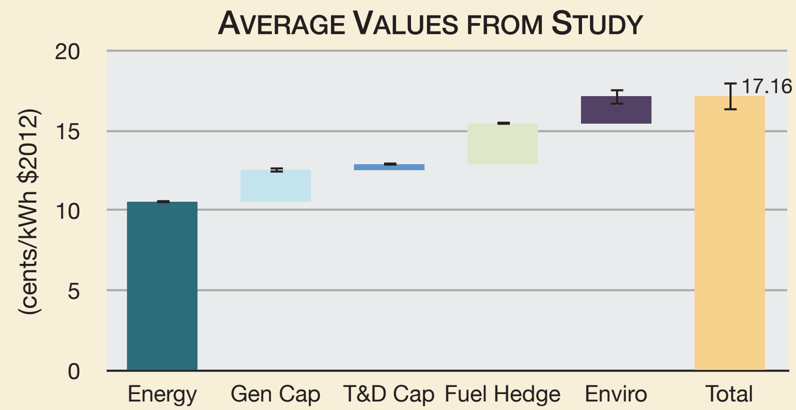
Environmental: Environmental cost of a displaced conventional generation technology times the portion of this technology in the energy generation mix, repeated and summed for each conventional generation sources displaced by PV. Environmental cost for each generation source based on costs of GHG, SOx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

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.

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

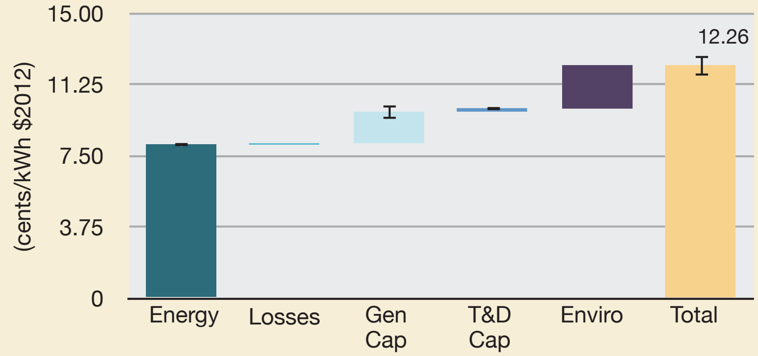
STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To quantify the comprehensive value of DPV to Austin Energy (AE) in 2006 and document methodologies to assist AE in performing analysis as conditions change and, to apply to other technologies
GEOGRAPHIC FOCUS	Austin, TX
SYSTEM CONTEXT	Municipal utility
LEVEL OF SOLAR ANALYZED	>1% - 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

eLab 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.

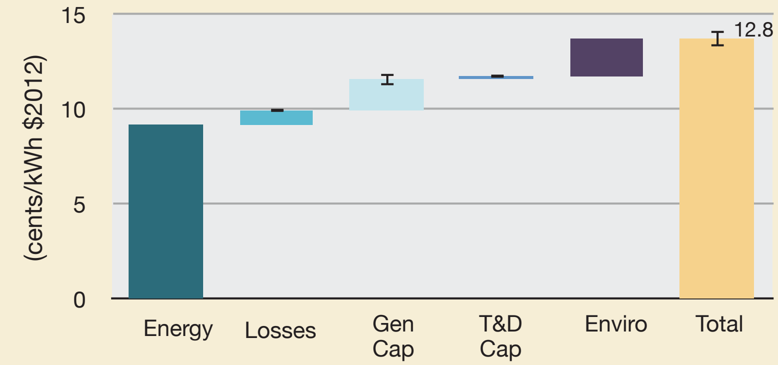
- As with the AE/CPR 2006 study, avoided energy costs are the most significant source of value, which is very sensitive to natural gas price assumptions.

- 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

AVERAGE VALUES FROM STUDY



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

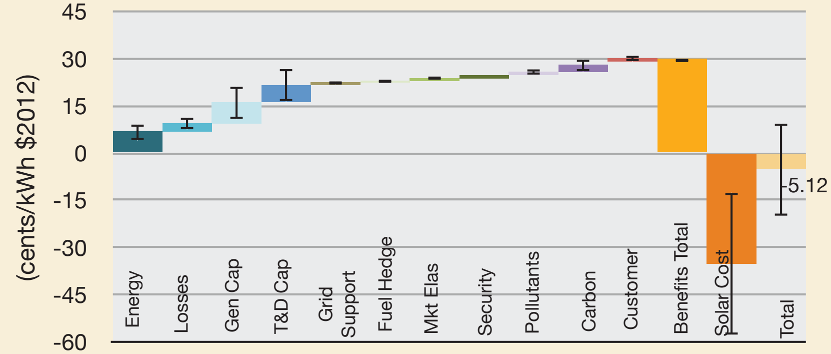
STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To summarize and describe the methodologies and range of values for the costs and values of 19 services provided or needed by DPV from existing studies.
GEOGRAPHIC FOCUS	Studies reviewed reflected varying geographies; case studies from TX, CA, MN, WI, MD, NY, MA, 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

AVERAGE VALUES FROM STUDY



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

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
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 & Austin Energy
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	
Contreras, J.L., Frantzis, L., Blazewicz, S., Pinault, D., Sawyer, H., *Photovoltaics Value Analysis.* Navigant Consulting, Feb, 2008.	National Renewable Energy Laboratory	Navigant Consulting, Inc.
Hoff, T., Perez, R., Braun, G., Kuhn, M., Norris, B., *The Value of Distributed Photovoltaics to Austin Energy and the City of Austin.* Clean Power Research, March 2006.	Austin Energy	Clean Power Research
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

Exhibit DG-3

The Mendota Group, LLC
the power of bright ideas

Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments

for Public Service Company of Colorado

October 23, 2014

Table of Contents

Executive Summary

Energy efficiency (EE) program cost-effectiveness evaluations assess the value (benefits) of these programs to a utility's system and aim to determine whether benefits exceed costs. The value of the generation and delivery system investments *avoided* or *deferred* by EE are components of the estimates of such benefits. Although estimates of avoided investments in and operation of generating units are fairly straightforward and tend to focus on a limited number of types of such units estimates of avoided investments in and operation of transmission and distribution (T&D) system components tend to be less straightforward. The following analysis examines ways in which utilities in the United States estimate EE program avoided transmission and distribution costs and provides a survey of current estimates.

Utilities have used a number of methods for estimating avoided T&D and there is no one "best" approach to developing these estimates. This report conducts a fairly broad benchmarking study of other utilities' estimates of avoided T&D costs. The benchmarking study produced a wide range of estimates for avoided T&D, underscoring the diverse nature of the methods used to calculate avoided costs. Although the process of estimating avoided transmission and distribution costs for EE programs has a long history it appears that it remains a dynamic area that will continue to evolve in the years to come. With this in mind, it would serve PSCo well to revisit this issue in the coming years.

A. Study Purpose

Xcel Energy (the "Company" or "PSCo") uses estimates of transmission and distribution facilities avoided or deferred by investments in energy efficiency in its EE cost-effectiveness evaluations. However, these estimates were developed nearly 10 years ago. It is useful at this point to refresh the Company's understanding of the way that U.S. utilities are calculating their avoided T&D for use with EE program cost-benefit analyses. The Company has requested assistance in researching other utilities' T&D estimates and the basis for those values.

To this end, the consultants sought to accomplish the following tasks:

- **Task 1. Research methods of estimating avoided T&D costs –** Consultant will survey methods used in most recent estimates of T&D avoided costs.
- **Task 2. Identify comparable utilities/systems and benchmark –** Consultant will identify at least five comparable utilities with which to compare and benchmark estimates for the Company.
- **Task 3. Conduct surveys/research of comparable utilities –** T&D cost assumptions and the methodologies used to derive them are often not readily available through publicly available information. Thus, Consultant may need to contact some of utilities to determine avoided T&D information.

The following report is the product of these tasks and seeks to answer each of the questions raised.

B. Issue Overview

Utility-administered electric energy efficiency programs benefit utility ratepayers by reducing the amount of electricity end-use customers consume for a given amount of production (e.g. lumens, cooling load, production from an assembly line, etc.). For the utility, this reduced electricity use translates to less electricity that its power plants must produce (or that the utility must purchase) to meet customer requirements. Over the longer term, it also reduces the need to construct new or expand existing generating facilities. These investments in end-user energy efficiency may also reduce the T&D system capacity needed to transport electricity from power plants to customers.

With respect to T&D systems, it is feasible that EE can avoid or delay T&D upgrades, and reduce construction and associated operations and maintenance costs, including cost of capital, taxes and insurance. If EE measures help reduce demand during peak periods, EE investments can also reduce the timing of maintenance, because frequent peak loads at or near design capacity will reduce the life of some types of T&D equipment.[1]

EE program administrators typically use estimates of investments in generation, transmission, and distribution (GT&D) "avoided" to calculate the cost-effectiveness of investments in energy efficiency programs. According to the *California Standard Practice Manual,* "the benefits calculated in the Total Resource Cost Test are the avoided supply costs, the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction."[2] The *National Action Plan for Energy Efficiency* (NAPEE) explains,

> The resource benefits of energy efficiency fall into two general categories:
> (1) Energy-related benefits that affect the procurement of wholesale electric energy and natural gas, and delivery losses,
> (2) Capacity-related benefits that affect wholesale electric capacity purchases, construction of new facilities, and system reliability.[3]

However, while estimates of avoided supply costs associated with the reduction in generation and capacity costs have more narrowly focused on capacity costs associated with a natural gas-fueled combustion turbine (CT) generating unit (and occasionally a combined cycle unit) and system-wide marginal energy costs,[4] estimates of avoided costs associated with T&D have varied

[1] "Assessing the Multiple Benefits of Clean Energy, A Resource for States," U.S. Environmental Protection Agency, Revised September 2011, p. 75.

[2] "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects," California Public Utilities Commission, October 2001, p. 18.

[3] "National Action Plan for Energy Efficiency," U.S. Department of Energy, U.S. Environmental Protection Agency, July 2006, p. 3-3.

[4] "Best Practices in Energy Efficiency Program Screening," Synapse Energy Economics for National Home Performance Council, July 23, 2012, p. 23. In some states, administrative rules dictate what type of generating unit will be used to calculate costs (see Iowa and Texas as examples).

widely. Although some of this variation may result from actual cost differences between utilities, much appears to also relate to variations in the way utilities calculate such costs.

Estimating avoided transmission and distribution costs is inherently more complex than generation because T&D benefits from EE tend to be location-specific, system-wide and time dependent. In other words, large amounts of EE investment in a specific part of the distribution grid could more significantly impact, say, required upgrades to a specific substation. On the other hand, system-wide energy efficiency investments can effectively reduce overall loading on transmission and distribution lines but still may not affect T&D investments unless the measures are coincident with system peaks.

Transmission and distribution systems are designed to carry extreme peak loads, which increases costs. States that use marginal cost of service studies to set rates regularly look at the cost to add T&D capacity. Put plainly,

> The capital cost of augmenting transmission capacity is typically estimated at \$200 to \$1,000 per kilowatt and the cost of augmenting distribution capacity ranges between \$100 and \$500 per kilowatt. Annualized values (the average rate of return multiplied by the investment over the life of the investment) are about 10% of these figures, or \$20 to \$100 per kilowatt-year for transmission and \$10 to \$50 per kilowatt-year for distribution. There are also marginal operations and maintenance costs for transmission and distribution capacity, but these are modest in comparison to the capital costs.[5]

But not all forecast T&D investments are deferrable or avoidable. “Some will be required to address time-related deterioration of equipment or other factors that are independent of load.”[6] One of the primary drivers of investment is the growth in the number of customers, which is not avoidable load growth. Other investments only a portion of which may be deferrable/avoidable from EE include modernization projects to improve technology, reliability improvements related to changes in reliability or safety standards, and projects to accommodate non-native load or supply, among others.

Authors Chris Neme and Rich Sedano categorize the manner in which efficiency programs can defer T&D investments as “passive” or “active”. Passive refers to deferred investments in transmission and distribution that occur as a byproduct of EE investments whereas active deferrals are those that result from EE initiatives targeted at specific locations. Active deferrals have the express purpose of deferring T&D investments. The authors cite a host of reasons as to why active deferrals are uncommon.[7]

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[5] “Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements,” Jim Lazar, Xavier Baldwin, Regulatory Assistance Project, August 2011, p. 6.

[6] “US Experience with Efficiency As a Transmission and Distribution System Resource,” Chris Neme (Energy Futures Group), Rich Sedano (Regulatory Assistance Project), February 2012, p. i.

[7] “US Experience with Efficiency As a Transmission and Distribution System Resource,” p. i. Among the reasons active deferrals lack popularity are: utility disincentives, difficulty in conducting T&D planning holistically, technical limitations, system engineers biased against demand resources, and risk aversion, among others.

Further to this point, "passive deferral occurs when the growth in load or stress on feeders, substations, transmission lines, or other elements of the T&D system is reduced as a result of broad-based (e.g., statewide or utility service territory-wide) efficiency programs."[8] Estimates of savings from EE investments "are typically developed by dividing the portion of forecast T&D capital investments that are associated with load growth (i.e., excluding the portion that is associated with replacement due to time-related deterioration or other factors that are independent of load) by the forecast growth in system load."[9] Section C discusses in more detail the different ways that utilities estimate avoided transmission and distribution costs.

It bears repeating that investments in transmission and distribution systems have other benefits beyond meeting load growth, including providing reliable service and meeting the needs of a growing number of customers. Investments in system improvements can also provide production cost savings through reduced line losses and reduced congestion, generation capacity cost savings by providing access to lower cost resources, and increased employment activities, among others.[10] This is relevant because it points out that while energy efficiency investments may defer or avoid transmission and distribution investments that such investments may provide other benefits that contribute (and are economically valuable) to the electricity system (thereby arguing that avoided cost estimates may be mitigated somewhat by ancillary benefits associated with these improvements). The next section discusses some common methods for calculating avoided T&D costs.

C. Common T&D Avoided Cost Calculation Methodologies

As previously discussed, there is little consistency between jurisdictions in terms of how avoided T&D costs are calculated. Unlike estimates of avoided energy and generating capacity, estimates of avoided T&D tend to require a fair amount of subjectivity in determining what to include in and what to exclude from calculations. Each utility has a different take on the topic and regulators to the extent they become involved in the issue also differ. Some utilities do not include estimates of avoided T&D in their evaluations, believing that EE does not defer T&D investments.[11] Other utilities, like those in Idaho, may include avoided transmission costs in calculations but place the value at zero because the generating unit avoided is close to load, thereby deferring no transmission.[12]

As such, determining what constitutes "best practice" becomes difficult, particularly because none of the different approaches are necessarily *wrong*. It is just that there are a variety of methods for developing the estimates, and each <u>may</u> be capable of producing valid estimates.

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[8] "US Experience with Efficiency As a Transmission and Distribution System Resource," p. 3.

[9] "US Experience with Efficiency As a Transmission and Distribution System Resource," p. 3.

[10] "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments," The Brattle Group, July 2013, p. 10.

[11] See "Consumers Energy: 2012-2015 Amended Energy Optimization Plan," Submitted to Michigan Public Service Commission (Case No: U-16670), August 1, 2011, p. 25.

[12] "Reviving PURPA's Purpose: The Limits of Existing State Avoided Cost Ratemaking Methodologies in Supporting Alternative Energy Development and A Proposed Path for Reform," Prepared by Carolyn Elefant, 2011, p. 31.

The uncertainty stems, in part, from the nature of energy efficiency as relying upon the counterfactual (i.e., the determination of what would have happened on the system if the EE program did not exist). To devise an analytical tool that enables one to assess the benefits and costs of EE requires that practitioners develop "good" estimates of the benefits EE investments produce. Good estimates are those based on sound principles as discussed in the following sections. The following section outlines a number of the methods while Appendix A provides an assessment of the strengths and weaknesses of the different approaches. Section D follows with a survey of a number of utilities' avoided cost estimates.

a. System Planning Approach

According to the U.S. Environmental Protection Agency's (EPA's) "Assessing the Multiple Benefits of Clean Energy (September 2011)," the *system planning approach* is the best way to estimate avoided T&D costs. "The system planning approach uses projected costs and projected load growth for specific T&D projects based on the results from a system planning study—a rigorous engineering study of the electric system to identify site-specific system upgrade needs. Other data requirements include site-specific investment and load data. This approach assesses the difference between the present value of the original T&D investment projects and the present value of deferred T&D projects."[13]

The U.S. EPA endorses this approach and suggests use of proprietary models of T&D system operation (two cited are PowerWorld Corp's model and the Siemens [PSS®E] model) to identify location and timing of system stresses. The system planning approach may well be the best way to estimate avoided T&D costs; however, the approach seems primarily to have been used to analyze investments in specific T&D projects rather than to analyze the system as a whole. The approach has been used to estimate the value of distributed generation and energy efficiency at ConEdison, Bonneville Power Administration, Efficiency Vermont, Detroit Edison, and Southern California Edison, among others.[14] However, these projects all appear to be aimed at "active" deferrals rather than the more typical passive deferrals.

b. Mix of Historical and Forecast Information Approach[15]

The ICF Tool, developed by ICF International, Inc. best exemplifies the Mix of Historical and Forecast Information approach. ICF developed a calculation methodology as part of a 2005 report prepared for the Avoided-Energy-Supply-Component (AESC) Study Group, whose members included utilities in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.[16] The report was commissioned to review energy supply costs avoided in the Northeast through energy efficiency programs. The AESC report has been updated biennially since 2005, but there have been no substantive changes to the calculator.

At its core, the ICF Tool collects data on historical and forecast T&D investments, determines what portions are due to load growth, and weights the historical and forecast contributions to

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[13] "Assessing the Multiple Benefits of Clean Energy," p. 76.

[14] "Best Practices in Energy Efficiency Program Screening," p. 25.

[15] This is a made-up label. Some have called this "projected embedded cost analysis" (see "Best Practices in Energy Efficiency Program Screening," p. 24.

[16] "Avoided Energy Supply Costs in New England: 2005 Report," Prepared for Avoided-Energy-Supply-Component (AESC) Study Group by ICF Consulting, December 23, 2005.

arrive at transmission and distribution T&D capacity marginal costs in $/kW-year. The tool takes the form of an Excel spreadsheet with four schedules (Schedule 1 is a summary) and an appendix. The Tool recommends that the user input 15 years of historical data and 10 years of forecast data for T&D capital investments and peak load. In addition, the user must input a variety of values from their FERC Form 1, including: property taxes, insurance costs, and operation and maintenance expenses. The user must also estimate the portions of investments identified in FERC Form 1 that are related to increasing load.[17]

The benefits of this methodology are that the Tool is well established, much of the data is available through FERC Form 1, and utilities and Commissions in the Northeast have been vetting it for nearly ten years. Many utilities continue to use the approach. The concerns with this method are that despite data being available from the FERC Form 1, the Tool still requires the user to make a subjective analysis of the proportion of investments resulting from increasing load. In addition, the 2009 AESC Report pointed out a number of potential calculation errors in the spreadsheet.[18]

c. Current Values Approach

The Current Values approach is well exemplified by MidAmerican Energy Company in its multiple state demand-side management (DSM) filings. MidAmerican has a standardized approach to calculating T&D capacity avoided costs in each of the states where it offers energy efficiency programs including Iowa, Illinois and South Dakota. This methodology is detailed in the direct testimony of Jennifer L. Long, in Iowa Docket No. EEP-2012-0002.

MidAmerican calculates T&D avoided costs as follows,

> The average cost to serve existing load is calculated for both the transmission and distribution systems by dividing each system's net cost by each system's peak capability. MidAmerican's Federal Energy Regulatory Commission (FERC) Form 1 data is used to calculate the net costs of the transmission and distribution systems by taking MidAmerican's original cost of plant less accumulated depreciation for each respective system. Yearly, MidAmerican load data and generation capability data is used to approximate the capacity of each system. The end result of the calculation is a $/kW cost for each system.[19]

The biggest strength of this method is its simplicity, which lends itself to frequent updates.

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[17] FERC Form 1, submitted annually by large utilities, provides comprehensive financial and operating results of the utility for the previous year. Investments specifically targeted for addressing load growth are not identified therein.

[18] "Avoided Energy Supply Costs in New England: 2009 Report," Prepared for Avoided-Energy-Supply-Component (AESC) Study Group by Synapse Energy Economics, Inc., August 21, 2009, p. 6-67.

[19] "Direct Testimony of Jennifer L. Long," Application for Approval of Energy Efficiency Plan for 2014-2018 (Docket EEP-2012-0002), Submitted to Iowa Public Utilities Board by MidAmerican Energy Company, Feb. 1, 2013, p. 4. Note that MidAmerican modified its approach to incorporate on peak load data instead of generation capability data.

d. Rate Case Marginal Cost Data with Allocators Approach

There are a few variations on the theme of using most recent marginal cost of service data from the utility rate case to develop estimates of avoided transmission and distribution costs. In California, T&D avoided costs are considered unique among other types of avoided costs in that both the value and hourly allocations are location specific. This information is combined with utility rate case information to calculate avoided costs separately for each utility.

As discussed in the 2011 update to the state's avoided costs,

> … the value of deferring distribution investments is highly dependent on the type and size of the equipment deferred and the rate of load growth, both of which vary significantly by location. Furthermore, some distribution costs are driven by distance or number of customers rather than load and are therefore not avoided with reduced energy consumption. However, expediency and data limitations preclude analysis at a feeder-by-feeder level for a statewide analysis of avoided costs. The costs taken from utility rate case filings are used as a reasonable proxy for the long-run marginal cost T&D investment that is avoided over time ...[20]

The avoided cost calculations also allocate T&D capacity values in each climate zone to the hours of the year during which the system is most likely to be constrained and require upgrade (the hours of highest local load). Although these values were previously based on hourly temperature values for the individual climate zones the information has since been updated for cost-effectiveness calculators (but not yet incorporated into the EE calculator) due to the availability of utility information on actual substation load data.[21]

e. Rate Case Marginal Cost Data Approach

Ameren Missouri goes through a fairly detailed review of its distribution and transmission system investments to determine the marginal cost of system capacity as it relates to load growth. However, this is complicated by the fact that "projects serve a variety of purposes; capacity upgrades to serve incremental system load, capacity upgrades to serve relocated system load, and refurbishment or replacement of equipment to avoid imminent failure."[22] As Ameren points out, analyzing the system in aggregate rather than focusing on specific areas further complicates the estimates, mainly because energy efficiency programs are designed to target specific areas.

PacifiCorp includes avoided T&D credits in its assessment of resources as part of its IRPs filed in Oregon, Washington, Idaho, California, Wyoming, and Utah. Specifically, PacifiCorp uses a cost of service study to derive the estimates. As part of the study, PacifiCorp estimates the demand-related substation costs by taking the total substation capacity expansion investment for the subsequent five years, dividing by the total increased capacity in kVA and then annualizing this number by multiplying by a carrying charge. The method of estimating demand-related transmission costs is similar. All "growth-related" transmission investment (with some

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[20] "Energy Efficiency Avoided Costs 2011 Update," by Brian Horii, Eric Cutter (Energy and Environmental Economics, Inc.), December 19, 2011, p. 24.

[21] "Energy Efficiency Avoided Costs 2011 Update," p. 26.

[22] "Ameren Missouri - 2011 Integrated Resource Plan," File No. EO-2011-0271, February 23, 2011.

exceptions like bulk power lines) over the subsequent five years is divided by the forecasted change in peak over the same period and this value is annualized.[23]

In its 2013 IRP, Nevada Energy uses the marginal cost study associated with the utility's 2010 rate case (Docket No. 10-06001) to determine its avoided T&D costs. As the utility states in its filing, "the adopted valuation process reduces potential difficulties regarding uncertainty in load forecasts and T&D construction budgets, and takes into account the ripple effect or the effect of deferred construction investments during the useful life of energy efficiency measures."[24] The Company, in turn, utilizes the conservative value of 25 percent of $47.50/kW (annual revenue requirement for the marginal cost of transmission facilities and distribution system, not accounting for the distribution beyond substation) or $11.88/kW in cost effectiveness analysis, and escalates it in each year by applying a cost construction index. The company further acknowledged that this is a low value when compared to other states like California.

Selection of Other Approaches

Averaging Method

In a note to the Vermont Public Service Board, a consultant outlines the various options available for calculating avoided T&D costs and cites among the options the "New England Average Method."[25] This method proposes using a New England average avoided T&D cost of $83 calculated from the figures identified in the 2011 AESC report. Although Vermont did not adopt this method other utilities have used a similar approach. Wisconsin Focus on Energy, which does not have explicit avoided T&D costs in its cost-effectiveness calculations, used an Iowa average for its market potential study.[26] In the Pacific Northwest, the Northwest Conservation and Electric Power Plan uses an average of avoided costs from a selection of utilities.[27]

IRP Approach

Some utilities use a variant of the System Planning Approach by conducting with and without DSM analyses to estimate avoided T&D costs.[28] Tucson Electric Power (TEP) conducts a decrement study to assess how transmission costs are avoided and uses this calculation in the utility's EE cost-effectiveness evaluations. It does not appear that TEP includes avoided distribution costs in its calculations and the utility only publishes its total avoided capacity costs. The utility considers the details proprietary and, therefore, specific information is not available.

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[23] Correspondence with PacifiCorp representatives, August 22, 2014.

[24] Sierra Pacific Power Company d/b/a NV Energy Integrated Resource Plan 2014-2033, Demand Side Plan 2014-2016," p. 48.

[25] "List of Possible Methods for Determining Avoided Transmission and Distribution Costs," Submitted to Vermont Public Service Board, June 28, 2012, http://psb.vermont.gov/docketsandprojects/eeu/avoidedcosts/2011.

[26] "Minutes and Informal Instructions of the Open Meeting of Thursday, July 10, 2014," Public Service Commission of Wisconsin, p. 3.

[27] "Appendix E – Conservation Supply Curve Development" in Sixth Northwest Conservation and Electric Power Plan, February 1, 2010, p. E-13, https://www.nwcouncil.org/energy/powerplan/6/plan/.

[28] This version of the System Planning Approach is more frequently associated with calculations of avoided generation energy and capacity costs. See "The Role and Nature of Marginal and Avoided Capacity Costs in Ratemaking: A Survey," Hethie Parmesano and William Bridgman, National Economic Research Associates, January 1992, p. 13.

Others

The memo to the Vermont Public Service Board also identified a method termed the "Simple Method" which relies on taking representative samples of recent T&D upgrade projects, dividing by increased capacity and annualizing.[29] The formula follows:

(Cost of Upgrades) ÷ (Additional Capacity Achieved by the Upgrade) ÷ (Economic Life of Upgrade)

A final method entails looking at each potential cost category of T&D capital costs and operations and maintenance expenses and making educated guesses as to the percentage of the cost category that is deferrable by EE. This can be applied to historical and, if available, forecast costs to determine the annualized value as it applies to load growth.

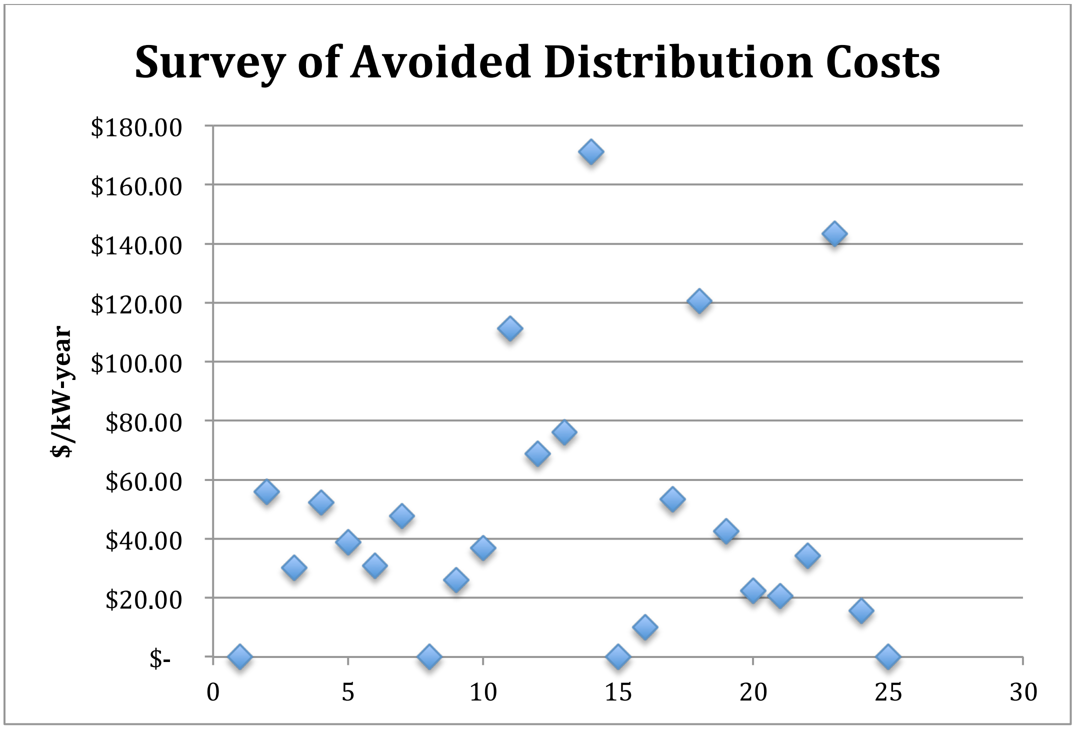
D. Survey of Other Utilities / Benchmarking

As part of Tasks 2 and 3, the authors collected avoided T&D data from a fairly broad cross-section of utilities. Data collection efforts sought to maximize the number of data points while also making an attempt to include utilities that might be most relevant to PSCo. However, it is unclear whether utility size or region has any bearing on estimated avoided costs and, therefore, the effort did not concentrate on the Rocky Mountain region or on comparably sized utilities. The survey does include some results from mountain states such as Arizona, Utah, Idaho and Nevada and also includes information from comparably sized (customers, sales) utilities (Consumers Energy [MI], Northern States Power [MN], Arizona Public Service [AZ]). Appendix B provides the detailed results of the survey. The range of data points for avoided Distribution cost estimates are provided below. The first section focus on distribution system estimates and it is followed by estimates of transmission system avoided costs. Combined estimates of avoided T&D are included in the final section.

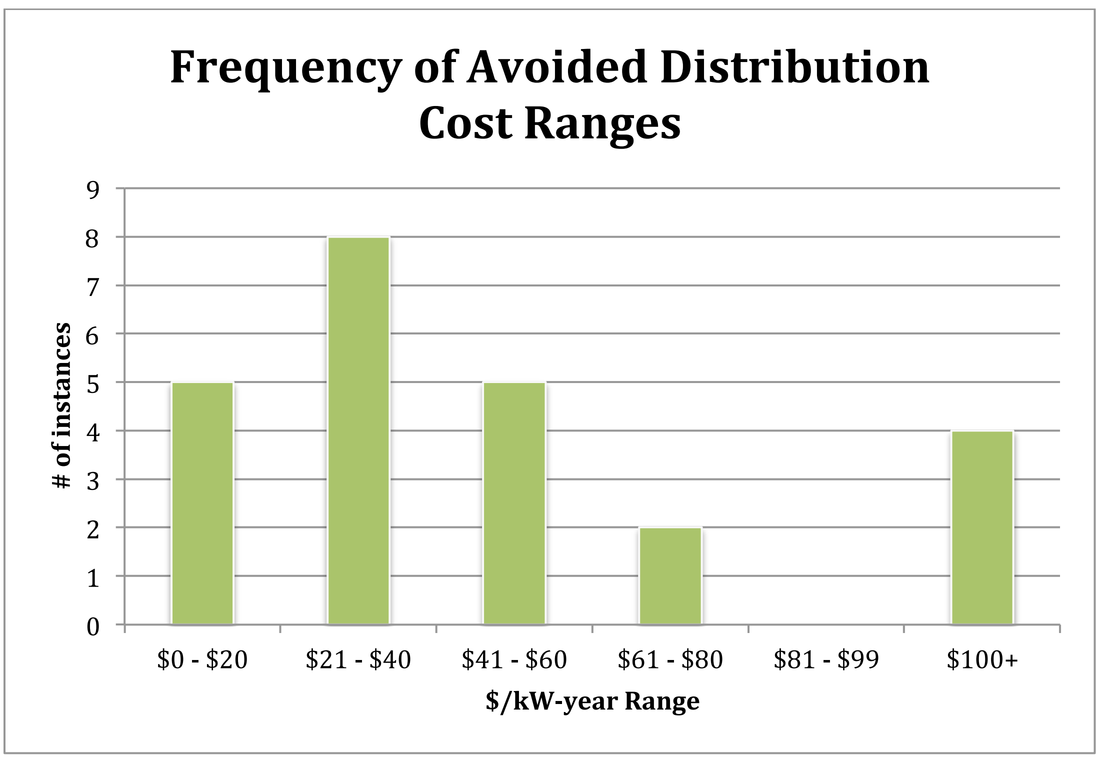
Estimates of Distribution System Avoided Costs

The average avoided distribution costs are $48.37 with a range from $0 to $171/kW-year.

[29] "List of Possible Methods for Determining Avoided Transmission and Distribution Costs," p. 2.

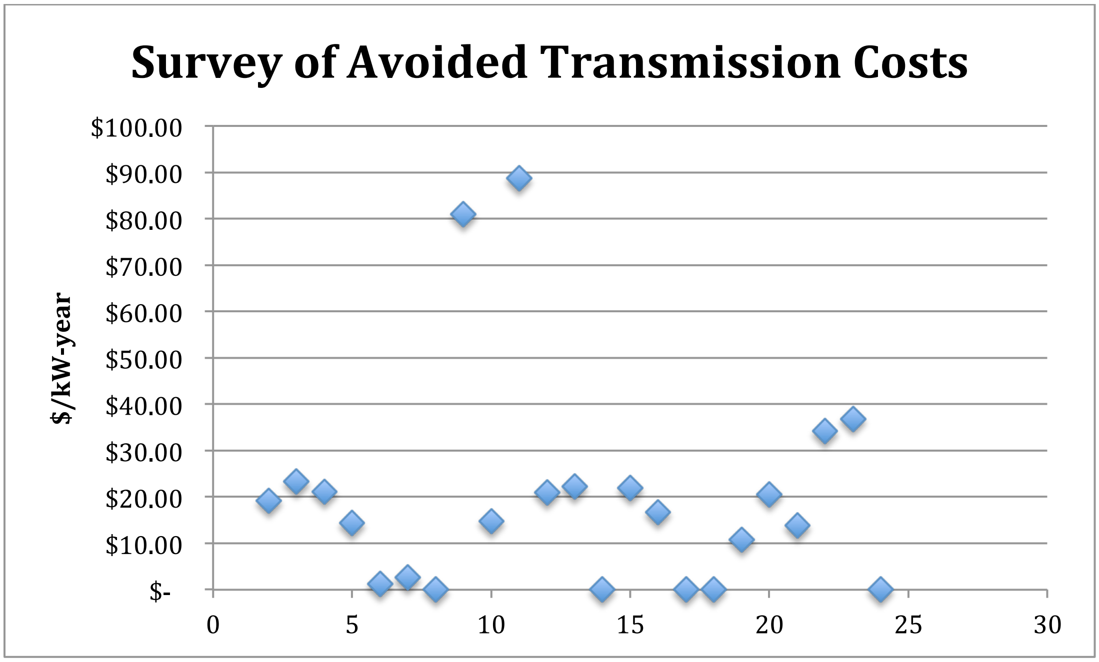


The values are most heavily concentrated in the $21 to $40 range with 8 of the samples falling in this range.

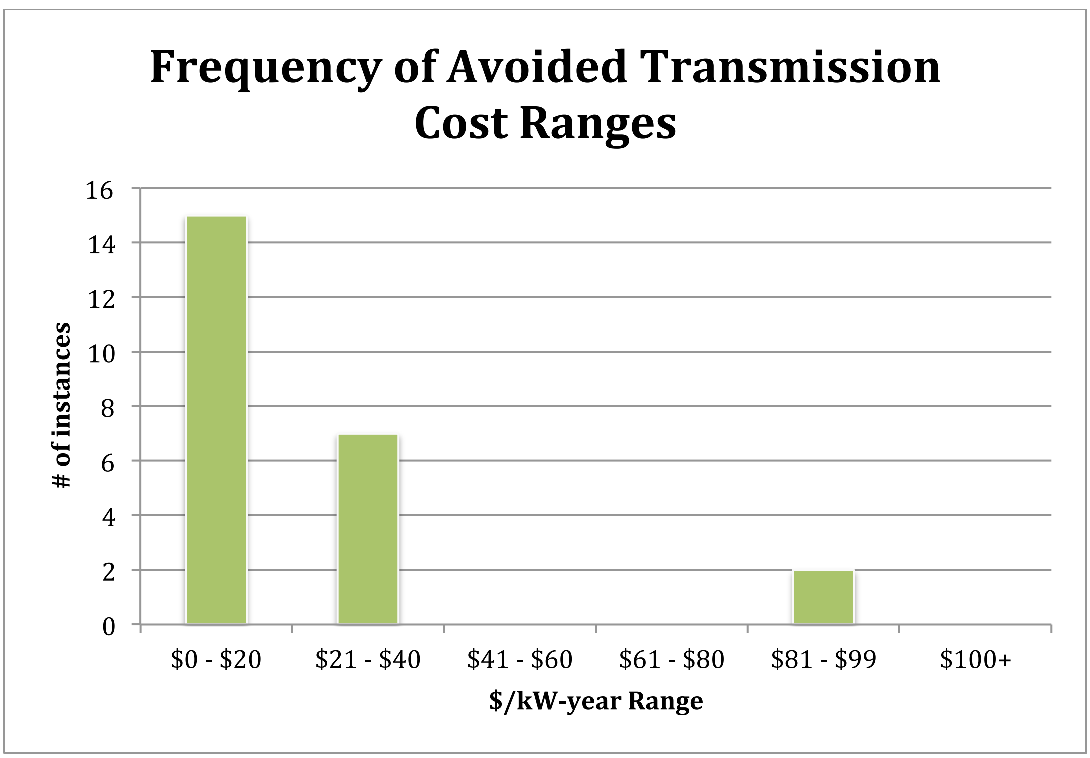


Estimates of Transmission System Avoided Costs

Average avoided transmission costs are $20.21 with a range from $0 to $88.64/kW-year.

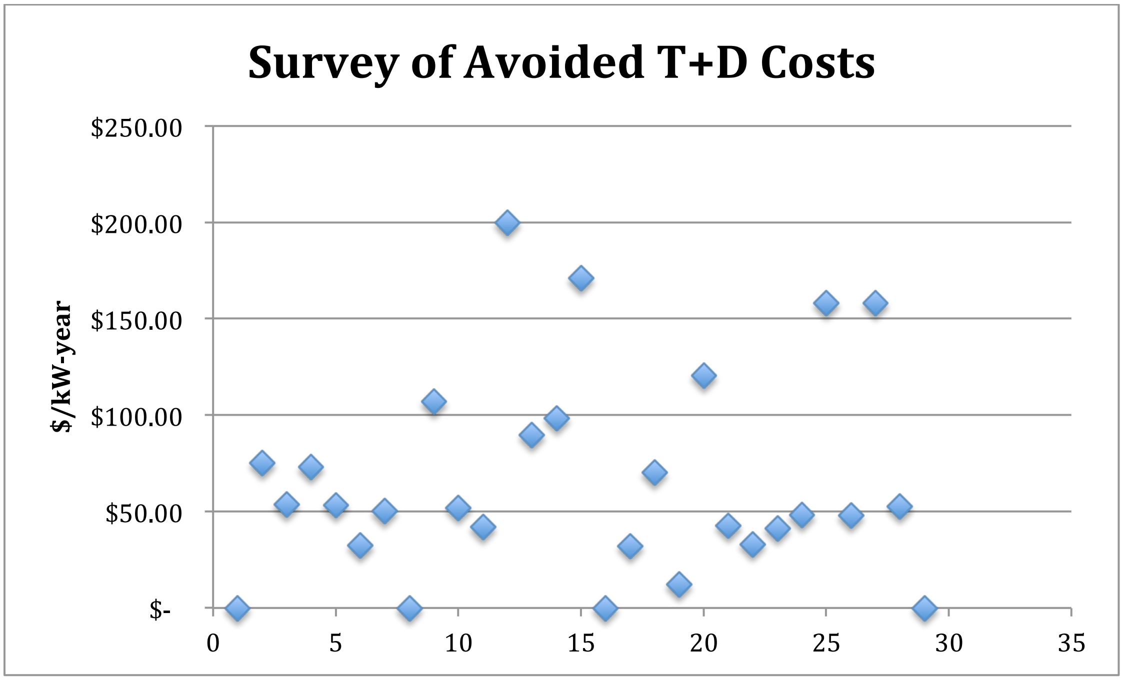


Transmission values are most heavily concentrated in the $0 to $20 range with 15 of the samples falling in this range

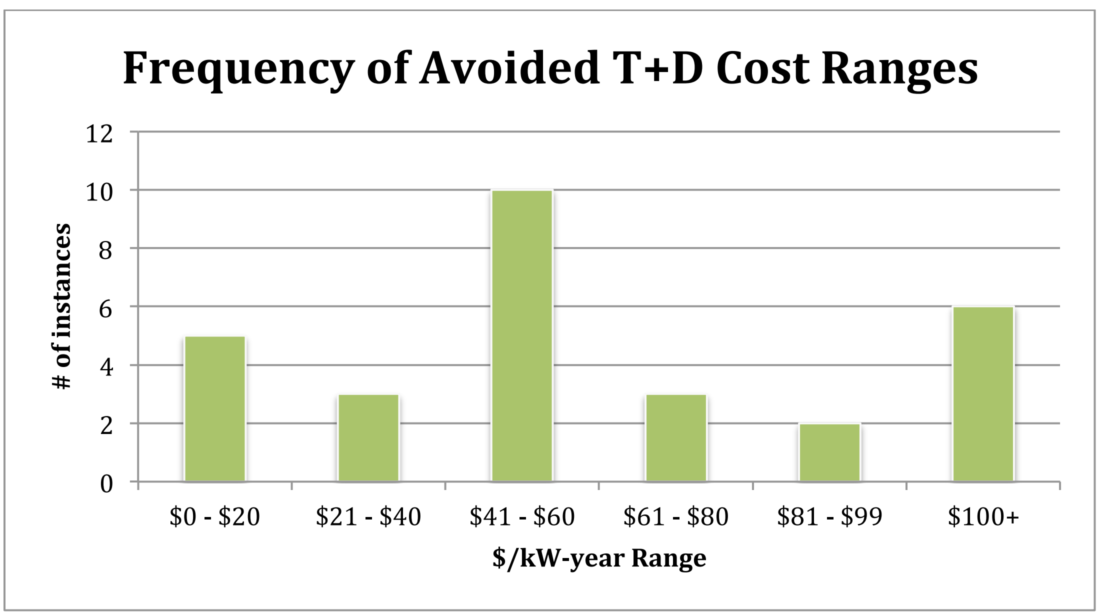


Estimates of T&D System Avoided Costs

Finally, the average avoided transmission + distribution costs are $66.03 with a range from $0 to $200.01/kW-year. It should be noted that there are more combined T&D results because some utilities did not break out T&D.



The values are most heavily concentrated in the $41 to $60 range with 10 of the samples falling in this range.



It should be further noted that the values for each entry were not adjusted for the applicable years, mainly because escalators were not available for all samples. The "oldest" data point is for 2011, so adjustments for inflation would not likely be significant.

Although this study did not explore the reasons for the differences between utility avoided costs, it is difficult to correlate relative values with overall utility retail rates or method of calculation. There can certainly be other factors that drive avoided T&D cost calculations. This is just to say that it is difficult to generalize and points out that there is a large amount of variability in estimated costs.

E. Conclusion

This study sought to investigate different ways that utilities in the United States estimated avoided transmission and distribution costs for energy efficiency cost-effectiveness evaluations that could inform its next DSM plan. The survey of methodologies and benchmarking determining that there are a variety of ways to estimate such values and a very broad range of estimates among the 35 utilities included. Given the dynamic state of the methodologies used to develop these estimates it is recommended that PSCo periodically revisit this issue and update the survey of current estimates and the methodologies used.

Appendix A – Selection of Approaches to Calculating Avoided T&D Costs

Method	Brief Description	Examples	Strengths	Weaknesses
System Planning Approach	• Uses costs and load growth for specific T&D projects based on a system planning study	• Vermont Electric Company (2003) – focused on specific transmission upgrade	• Potentially more accurate • Uses specific project data to develop estimates • Forces consideration of DER effects on project-by-project basis	• Costly and time consuming • May not be appreciably more accurate than other approaches • Dependent upon individual projects included in analysis
Mix of Historical and Forecast Information	• Uses data on historical and forecast T&D investments, determines what's related to load growth, and weights the historical and forecast contributions	• ICF Tool used in the Northeast, Vermont DPS variation	• Uses publicly available FERC Form 1 data • Easily calculated and updated • Uses a form of marginal costs • Addresses "lumpiness" of T&D investments • Used by multiple other states • Relies upon historical as well as forecast information	• Assumes it's possible to differentiate amount of T&D investment that corresponds to load growth rather than maintenance, reliability and customer growth • Does not incorporate variability associated with time/location differences • Can't readily handle low forecast growth
Current Values	• Develops average cost to serve existing load by dividing each system's net cost	• MidAmerican Energy (IA, IL, SD), Commonwealth Edison (IL)	• Uses publicly available FERC Form 1 data • Easily calculated and updated	• May tend to undervalue • Does not incorporate variability associated with time/location differences

Method	Brief Description	Examples	Strengths	Weaknesses
Rate case marginal cost data with allocators	• Uses T&D marginal cost of service data from utility rate cases and apply time and locational factors related to weather or specific substation loadings	• California IOUs	• Uses publicly available data (rate case portion) • Uses approach consistent with ratemaking • Uses time and location differentiated data • Uses marginal cost information	• Potentially costly and time consuming • May not be appreciably more accurate than other approaches • Somewhat assumes use of hourly avoided costs for Generation • Requires estimation of investments deferred by EE
Rate case marginal cost data	• Use T&D marginal cost of service data from most recent rate case	• Ameren (MO), PacifiCorp (OR, UT, WA), Nevada Energy, Consolidated Edison (NY)	• Uses publicly available data • Is approach consistent with ratemaking • Uses marginal cost information	• May not be appreciably more accurate than other approaches • Requires estimation of investments deferred by EE
IRP Method	• Uses without and without EE runs to determine avoided transmission costs	• Tucson Electric Power	• Is consistent with integrated resource plan	• Is highly dependent on IRP's model ability to calculate transmission costs • Requires integrated resource plan • Only updated as frequently as resource plan • Typically can only provide transmission
Averaging method	• Take simple average of a selection of similar	• Wisconsin Focus on Energy Market Potential Study (used Iowa)	• Uses publicly available data • Very easily calculated	• Must pick appropriate proxy utilities for averaging

Method	Brief Description	Examples	Strengths	Weaknesses
	jurisdictions	• Northwest Conservation and Electric Power Plan (used 8 utilities)		• Not specific to one utility
Simple Method	• Take representative sample of recent T&D upgrade projects, divide by increased capacity and annualize	• Unknown	• Very simple • Provides real information from specific example • Can be done for transmission, distribution and sub-transmission	• Project may not be system representative • Must still determine what portion of increased capacity relates to load growth

Appendix B – Survey of Utility Avoided Transmission and Distribution Costs

Estimated Values

State	Utility	Date of Estimate	Transmission	Distribution	O&M	Total T&D	Units
AZ	TEP	2013	N/A	N/A		$100.00	$/kW-year
AZ	APS	2013	$0	$0		$0	
CA	PG&E-Com	2011	$19.60	$55.97		$75.57	$/kW-year
CA	PG&E-Res	2011	$18.77	$55.85		$74.62	$/kW-year
CA	SCE-Com	2011	$23.39	$30.10		$53.49	$/kW-year
CA	SCE-Res	2011	$23.39	$30.10		$53.49	$/kW-year
CA	SDG&E-Com	2011	$21.08	$52.24		$73.32	$/kW-year
CA	SDG&E-Res	2011	$21.08	$52.24		$73.32	$/kW-year
CA	Weighted Average	2011	$21.20	$44.38		$65.59	$/kW-year
CT	CL&P	2013	$1.30	$30.94		$32.24	$/kW-year
CT	United Illuminating	2013	$2.64	$47.82		$50.46	$/kW-year
ID	Idaho Power	2014	$0	$0		$0	
IA	Interstate Power & Light	2014	$81.00	$26.00		$107.00	$/kW-year
IA	MidAmerican	2013	$14.85	$37.01		$51.86	$/kW-year
IL	Commonwealth Edison	2014	N/A	N/A		$42.00	$/kW-year
MA	National Grid	2013	$88.64	$111.37		$200.01	$/kW-year
MA	NSTAR	2011	$21.00	$68.79		$89.79	$/kW-year
MA	WMeco	2011	$22.27	$76.08		$98.35	$/kW-year
MA	Unitil	2013	$0	$171.15		$171.15	$/kW-year
MI	Consumer's Energy	2012	$0	$0		$0	
MN	Xcel	2014	$14.31	$38.85		$53.17	$/kW-year
MO	Ameren	2014	$22.00	$10.00		$32.00	$/kW-year
NH	PSNH	2013	$16.70	$53.35		$70.05	$/kW-year
NW	NW Conservation and Electric Power Plan utilities	2010	$0	$23.00		$66.59	$/kW-year

Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments

State	Utility	Date of Estimate	Transmission	Distribution	O&M	Total T&D	Units
NV	Sierra Pacific Power dba Nevada Energy	2013	N/A	N/A		$12.23	$/kW-year
NY	Consolidated Edison (Network)	2013	$0	$120.52		$120.52	$/kW-year
NY	Consolidated Edison (Non-Network)	2013	$0	$42.63		$42.63	$/kW-year
OR	PacifiCorp	2011	$36.89	$15.75		$52.64	$/kW-year
OR	PGE	2011	$10.80	$22.40		$33.20	$/kW-year
RI	National Grid	2013	$20.62	$20.62		$41.24	$/kW-year
SD	MidAmerican	2012	$13.79	$34.37		$48.16	$/kW-year
UT	PacifiCorp	2011	$36.89	$15.75		$52.64	$/kW-year
VT	Burlington Electric Department (Prescriptive Programs)	2013	N/A	N/A		$158	$/kW-year
VT	Burlington Electric Department (Custom Programs)	2013	N/A	N/A		$48	$/kW-year
VT	Efficiency Vermont	2013	$34.25	$93.25	$50.00	$158.15	$/kW-year
WA	PacifiCorp	2011	$36.89	$15.75		$52.64	$/kW-year
WI	Focus on Energy		$0	$0		$0	

N/A refers to instances where the utility did not break out the individual transmission and distribution values.

Methods and Data Sources

State	Utility	Method	Data Source for Calcs	Notes
AZ	TEP	Calculated avoided G&T using IRP. Developed $/kW-year based on G&T costs avoided by selected DSM portfolio.	IRP	TEP considers the avoided capacity costs confidential as part of their Resource Plan. They do not provide detail in their EE Plan beyond the SCT (Societal Cost Test). Not included in averaging calcs.
AZ	APS			Does not specifically incorporate an avoided capacity value for T&D. Includes line losses for energy and capacity.
CA	PG&E-Com	The costs taken from utility rate case filings are used as a reasonable proxy for the long-run marginal cost T&D investment that is avoided over time with the addition of distributed energy resources.	General Rate Case	Only included PG&E Com/Res average in averaging calcs and graphs.
CA	PG&E-Res			
CA	SCE-Com		FERC Form 1	Only included one SCE in averaging calcs and graphs.
CA	SCE-Res		FERC Form 1	
CA	SDG&E-Com	The costs taken from utility rate case filings are used as a reasonable proxy for the long-run marginal cost T&D investment that is avoided over time with the addition of distributed energy resources.	General Rate Case	Only included one SDG&E in averaging calcs and graphs.
CA	SDG&E-Res			They are the same values used for the 2011 CEC California Building Energy Standards, and the CPUC CSI and DR proceedings.
MN	Xcel		Internal	
CT	CL&P	ICF Tool	FERC Form 1	
CT	United Illuminating	Black & Veatch Report		United Illuminating Avoided Transmission & Distribution Cost Study Report, Black & Veatch, September 2009.
IA	Interstate Power & Light		MISO Att. O for T.	
IA	MidAmerican	The average cost to serve existing load is calculated for both the transmission and distribution systems by dividing each system's net cost by each system's peak capability. MidAmerican's Federal Energy Regulatory Commission (FERC) Form 1 data is used to calculate the net costs of the transmission	FERC Form 1	Iowa EE rules do not required avoided T&D. Is done as an alternative calculation - rules dictate use of a CT for avoided capacity costs and provides the formula. Ratepayer advocates currently advocating for use of MISO Attachment O rates for avoided transmission

State	Utility	Method	Data Source for Calcs	Notes
		and distribution systems by taking MidAmerican's original cost of plant less accumulated depreciation for each respective system. MidAmerican T&D avoided costs are calculated using depreciated original cost figures listed in FERC Form 1.		(Docket INU-2014-0001)
IL	Commonwealth Edison	ComEd conducted an updated analysis to place a value on the avoidance or deferral of new transmission and distribution capacity as a result of energy efficiency. The most recent analysis determined that an avoided T&D cost of $42/yr. is appropriate for cost-effectiveness analysis.		8-27-14: The avoided T&D cost is from an internal study and does not have a breakdown between T and D.
MA	National Grid	ICF Tool	FERC Form 1	
MA	NSTAR	ICF Tool	FERC Form 1	
MA	WMeco	ICF Tool	FERC Form 1	
MA	Unitil	ICF Tool	FERC Form 1	
MI	Consumer's Energy			*While the cost of building transmission and distribution systems -- by either building with less capacity or avoiding building completely – theoretically might be avoided, Consumers Energy's current transmission and distribution systems are typically adequate to meet customers' needs. The current situation, relative to numbers of customers and demand, would need to substantially change before costs of building transmission and distribution systems could be avoided.*
MN	Xcel		Internal	
MO	Ameren	Rate case marginal costs	2010 Rate Case	
NH	PSNH	ICF Tool	FERC Form 1	
NW	NW Conservation and Electric Power Plan utilities	Used benchmarked data to come up with "representative" value. Estimated a value of $25 for transmission, but did not adopt. See notes.	Regional Technology Forum (RTF)	Is part of 6th 5-year Power Plan. Planning for 7th began in 2014. "The Council adopted the RTF recommended value for distribution system avoided cost. However, because the value of avoiding the transmission system investments is

State	Utility	Method	Data Source for Calcs	Notes
				already included in the wholesale market prices produced by the AURORA model the Council did not use the RTF estimate of the benefits of deferring transmission system expansion so as to avoid double counting." (p. E-14).
NV	Sierra Pacific Power dba Nevada Energy	Is the annual revenue requirement for T&D impacted by EE. Submitted as marginal cost study with rate case. 13-06002	Rate case T&D costs	Uses "conservative value" of 25% of T&D revenue requirements of $49.92 (was $47.50 in 2010 rate case). Does not account for distribution costs beyond the substation. Uses "PortfolioPro" cost benefit model developed for them by Cadmus. However, in IRP NVEnergy recognizes that its T&D costs are low based on Synapse's best practices study.
NY	Consolidated Edison (Network)	Marginal costs associated with load growth	Utility marginal cost data	Study developed in response to requirement from NY Public Service Commission. Network resources are associated with underground low-voltage distribution systems such as in downtown NYC. Emergence of T avoided costs do not occur until 2017.
NY	Consolidated Edison (Non-Network)	Marginal costs associated with load growth	Utility marginal cost data	Study developed in response to requirement from NY Public Service Commission. Non-Network resources are associated with radial distribution systems. Emergence of T avoided costs do not occur until 2017.
OR	PacifiCorp	Regulation Department provides as input to the IRP. Represents "an average of the values from a marginal cost of service study from the company's last 5 general rate cases for demand-related substation and transmission costs."	Rate case T&D revenue requirements	The resource deferral fixed cost benefit is comprised of the deferred capital recovery and fixed operation and maintenance costs of a "next best alternative" resource—a combined- cycle combustion turbine (CCCT).
OR	PGE	ICF Tool	FERC Form 1	
RI	National Grid	ICF Tool	FERC Form 1	
SD	MidAmerican	Avoided distribution costs are calculated by determining the economic carrying charge associated with MidAmerican's net distribution investment on a $/kW basis; Avoided transmission capacity costs are calculated by determining the economic carrying charges associated with MidAmerican's net transmission investment on a	FERC Form 1 and utility discount rates	Same values as Iowa and, therefore, not duplicated in averaging calcs

State	Utility	Method	Data Source for Calcs	Notes
		$/kW basis, where kW refers to the total transmission system capacity.		
UT	PacifiCorp	See OR		Same values as Oregon, and, therefore, not duplicated in averaging calcs
VT	Burlington Electric Department (Prescriptive Programs)			Different values for prescriptive and custom programs. Prescriptive values decline over time. Is 2012 $. Order on 12/13/2012 in Docket EEU-2011-02
VT	Burlington Electric Department (Custom Programs)	VT Department of Public Service adapted ICF Tool. Method used by AESC 2013, applicable to Vermont.		
VT	Efficiency Vermont	VT Department of Public Service adapted ICF Tool. Method used by AESC 2013, applicable to Vermont.		The statewide estimates are based on load-related investments in the last decade for which Vermont experienced significant load growth, ending in 1996. Adds O&M and then subtracts a "T&D offset". Order on 12/13/2012 in Docket EEU-2011-02, See values below through 2040
WA	PacifiCorp	See OR		Same values as Oregon and, therefore, not duplicated in averaging calcs
WI	Focus on Energy	$-	$-	Does not currently include avoided T&D in FOE cost effectiveness evaluations. Discussed possibility but felt that the effort would require considerable analysis to determine what was avoided. Uses MISO forecasted LMPs as primary energy avoided costs (no capacity apparently). But LMPs theoretically incorporate all (G, T&D). ECW 2009 market potential study incorporate $30/kW-year value in its analysis based on Iowa utilities' calculations.

Row		Value	Source
1	Tx Peak (MW)	14,355	2016 FERC Form 1
2	Peak (MW)	13,248	2016 FERC Form 1
3	Tx Year End Balance ($)	2,482,661,395	2016 FERC Form 1
4	Depreciation ($)	40,048,151	2016 FERC Form 1
5	Net Tx Year End Balance ($)	2,442,613,244	Row3 - Row4
6	Net Tx Balance ($/kW)	170.16	(Row5 / Row3) / 1000
7	Solar Summer Capacity Credit	44%	DEP 2017 IRP p 22
8	Solar Winter Capacity Credit	5%	DEP 2017 IRP p 22
9	Estimated Solar Capacity Factor	16.8%	PV Watts, Florence, SC
10	Summer Avoided Tx Value due to PV ($/kWh)	0.050851	(Row6 x Row7)/(8760 x Row9)
11	Winter Avoided Tx Value due to PV ($/kWh)	0.005778	(Row6 x Row8)/(8760 x Row9)